BEFORE THE

PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

In the Matter of the Application of HAWAIIAN ELECTRIC COMPANY, INC. For Approval of Rate Increases and Revised Rate Schedules and Rules	)))))))	DOCKET NO. 2008-0083

TESTIMONY OF RALPH C. SMITH, CPA

ON BEHALF OF

THE DEPARTMENT OF DEFENSE

AND

CERTIFICATE OF SERVICE

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ON BEHALF OF

THE DEPARTMENT OF DEFENSE

COMES NOW, DEPARTMENT OF DEFENSE by and through its undersigned attorney and hereby submits Testimony of Ralph C. Smith to Hawaiian Electric Company, Inc.

DATED: Honolulu, Hawaii, April 17, 2009

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Filed April 17, 2009

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RALPH C. SMITH

DOCKET NO. 08-0083

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I. INTRODUCTION

Q. Please state your name and business address.

A. Ralph C. Smith, 15728 Farmington Road, Livonia, Michigan 48154.

Q. What is your occupation?

A. I am a certified public accountant and a senior regulatory utility consultant with the firm Larkin & Associates, PLLC, certified public accountants and regulatory consultants.

Q. What is your educational background and professional experience?

A. These are presented as Exhibit DOD-100. This exhibit also summarizes some of my regulatory experience and qualifications.

Q. On whose behalf are you appearing?

A. My firm is under contract with the Navy Utility Rate and Studies Office (URASO) to perform utility revenue requirement studies. The Navy represents the Department of Defense (DOD) in Hawaii.

Q. Please describe the tasks you performed related to your testimony in this case.

A. We reviewed and analyzed data and performed other procedures as necessary (1) to obtain an understanding of the Hawaiian Electric Company Inc.'s ("HECO" or "Company") rate filing package as it relates to the operating income, rate base, and overall revenue requirement in this case and (2) to formulate an opinion concerning the reasonableness of amounts included within the Company's application for rate increase.

These procedures included reviewing the Company's testimony, exhibits and workpapers, issuing information requests, and analyzing HECO's responses to them.

Q. Have you prepared exhibits to present in support of your testimony?

A. Yes. I have prepared Exhibits DOD-101 through DOD-127.

Q. Were these exhibits prepared by you or under your supervision?

A. Yes, and they are correct to the best of my knowledge and belief.

Q. What issues will you be addressing in your testimony?

A. My direct testimony discusses the development of DOD's recommended adjustments to HECO's rate base, net operating income, and revenue requirement.

Q. Has HECO updated and/or revised its rate filing?

A. Yes. HECO has supplied updates in a series of letters and attachments.

Q. What amount of increased revenues is HECO seeking in this case?

A. HECO's direct filing, as summarized in HECO T-23, on pages 1-3, requested a rate increase of $97.011 million at "current effective" rates or $174.348 million at "present" rates. HECO's "current effective rates" included an interim rate increase from the Commission's Interim Decision and Order No. 23749 in Docket No. 2006-0386, HECO's rate case for test year 2007. HECO T-23, at page 3, directly attributes the difference of $77.337 million in revenues between present and current effective rates to the 2007 Rate Case Interim surcharge revenues.

Q. Has HECO revised its calculated revenue deficiency?

A. Yes. HECO filed its "December 2008 Update" for HECO T-23 on December 22, 2008, which contained recalculations of the Company's revenue deficiency. HECO T-23, Attachment 2 as "updated" by HECO now shows a revenue deficiency at "current effective rates" of $100.035 million. HECO T-23 Attachment 2 reflects the full cost of the Campbell Industrial Park Generating Station, Unit 1 ("CIP1"), but does not reflect the full cost of Wind Studies, and the impact of HECO's projected 2009 test year sales reduction.

Attachment 5 now shows a revenue deficiency at "present rates" of $176.892 million. HECO's Attachment 5 appears to be similar to Attachment 2 in terms of what is included, but the revenue deficiency in Attachment 5 is stated in terms of present rates, whereas HECO's Attachment 2 states the Company's requested revenue deficiency in terms of the increase over HECO's current effective rates.

HECO T-23, Attachment 7 shows a revenue deficiency at current effective rates of $90.666 million. Attachment 7 reflects HECO's base case, without HECO's projected 2009 sales reduction and with the cost of Wind Studies.

HECO has estimated the revenue requirement impact of including the Wind Studies (which HECO refers to as HCEI Implementation Studies) at $2.452 million.

Other revenue requirement iterations calculated by HECO are summarized in its rate case update for HECO T-23, in Attachment 1.

Q. What impact on HECO's calculated amounts of revenue deficiency did the Company's "December 2008 updates" have?

A. The impact of the various revenue requirement iterations presented by HECO is summarized in a table presented on HECO T-23, Attachment 1.

Q. What starting point did you utilize in determining HECO's 2009 rate base and net operating income?

A. I used HECO's Attachment 7 to HECO's T-23 update as my starting point and have reflected my recommendations as adjustments to that iteration of HECO's filings.

Q. What revenue requirement and basic assumptions were reflected in Attachment 7 to HECO's T-23 update?

A. HECO's Attachment 7 reflected an average 2009 test year rate base of $1.295 billion before working capital, and an average rate base after working capital of $1.335 billion. HECO indicates that its Attachment 7 includes cost for Wind Studies and is HECO's base case without a sales reduction. HECO's workpapers that were included with its Attachment 7 Excel file show Operating

Revenues of $1.867 billion, Operating Expenses of $1.800 billion, and operating income at current effective rates of $67.2 million. At HECO's proposed rate of return on rate base of 8.81%, HECO shows an operating income deficiency of $50.433 million and a revenue deficiency of $90.666 million.

Q. What reasons has HECO offered for not reflecting the impact of (1) its revised forecast for lower electric sales in 2009 and (2) the Wind Studies in the determination of its base rate revenue requirement?

A. In its rate case update for HECO T-23, at page 1, HECO states that "it is the Company's preference not to include the impacts of these two items in the test year revenue requirement." HECO's reason for not including the impact of its revised forecast for lower electric sales in 2009 is that the Company proposes to decouple revenues from sales through the establishment of a revenue balancing account, pursuant to Section 28 of the *Energy Agreement among the State of Hawaii, Division of Consumer Advocacy of the Department of Commerce and Consumer Affairs, and Hawaiian Electric Companies* ("HCEI Agreement"). HECO's reason for not including the Wind Studies cost is that HECO will propose, in a separate application, to recover the cost of the HCEI Implementation Studies through the Renewable Energy Infrastructure Program ("REIP") and Clean Energy Infrastructure ("CEI") surcharge, pursuant to Section 3 of the HCEI Agreement.

Q. Do you have a recommendation concerning whether HECO's revised forecast for lower electric sales in 2009 should be reflected in the determination of base rates, or addressed via some other method?

A. Not at this time. I am aware that HECO, the CA and other parties are addressing a Revenue Adjustment Mechanism ("RAM") in Docket No. 2008-0274 that would be an alternative method for addressing impacts of a revised sales forecast. I have reviewed some of the documents in that docket, including the *Joint Proposal on Decoupling and Statement of Position of the HECO Companies and the Consumer Advocate* ("Joint Proposal") filed March 30, 2009. For my calculation of the revenue deficiency in this proceeding, I have used as a starting point Attachment 7 from HECO's T-23 Update, which does <u>not</u> reflect the impact of the 2009 reduced sales forecast in determining the base rate revenue deficiency. However, this use is not intended to constitute a recommendation for or against treating HECO's reduced 2009 sales forecast in this manner.

Q. Another aspect of HECO's T-23 Update, Attachment 7 is the treatment of the cost for Wind Studies. Is your use of Attachment 7 as the starting point for your revenue deficiency calculations intended to constitute a recommendation for or against that particular treatment of Wind Studies cost?

A. No. My use of Attachment 7 as the starting point for my revenue deficiency calculations is not intended to constitute a recommendation for or against that treatment of Wind Studies cost. I am generally aware that HECO, the CA and other parties have been working through issues related to the HCEI Agreement. It is unclear to me at this point whether the treatment of Wind

Studies cost reflected in HECO's T-23 Update, Attachment 7, represents the preferable treatment of such costs for ratemaking purpose versus some other alternative; consequently, I am not offering an opinion or recommendations concerning that issue in my direct testimony.

Q. Another aspect of HECO's T-23 Update, Attachment 7 is that it reflects HECO's "base case" treatment for Campbell Industrial Park ("CIP") Combustion Turbine Unit 1 ("CT-1"), or "CIP1". In simple terms, what is HECO's "base case" treatment of CIP CT1?

A. CIP1 is not in-service at the beginning of the 2009 test year; however, HECO projects that it will be in-service during 2009. Consequently, HECO's "base case" treatment does not reflect CIP1 in beginning-of-test-year rate base but does reflect it in end-of-test-year rate base. In other words, HECO's "base case" treatment of CIP1 reflects it in average 2009 rate base.

Q. Has HECO presented in its Updates an alternative ratemaking treatment for CIP1?

A. Yes. Some of HECO's T-23 alternatives reflect a "full cost" treatment for CIP1. This essentially treats CIP1 in the 2009 rate base as if it were in-service at the beginning of the test year.

Q. Do you have a recommendation as to how the cost of CIP1 should be treated in determining HECO's revenue requirement in this case?

A. Yes. I recommend the "base case" or average test year treatment for CIP1 for these reasons. First, CIP1 was not in-service at the beginning of the test year. Second, including it in average test year rate base is consistent with the average test year concept that is being used to derive HECO's revenue deficiency. Third, while the Commission has allowed some exceptions to average test year treatment for major rate base additions on occasion in the past, the current HECO rate case must be viewed in the context of other developments, including the HCEI Agreement and the Joint Proposal, which provides specific details regarding how a Rate Adjustment Mechanism ("RAM") would provide for rate base. In this regard, the average rate base treatment of CIP1 appears to be consistent with the proposed derivation of Rate Base provided in the Joint Proposal. For example, the Joint Proposal provides at page 14 that: "The Rate Base (for the RAM Period) will be the average net investment estimated for the RAM period ..." Further, "the average rate base for the RAM period (i.e., the Rate Base) will be the rate base for the rate case test year, with adjustments for changes in only four components of rate base, including (1) plant-in-service, (2) depreciation reserve (i.e., "Accumulated Depreciation"), (3) accumulated contributions in aid of construction ("CIAC") and (4) accumulated deferred income taxes ("ADIT")." The Joint Proposal provides further that: "The average plant-in-service amount will be equal to the average of (1) the actual plant-in-service balance as of the end of the year prior to the RAM Period (termed the "Evaluation Year"), and (2) the same year-end balance plus estimated plant additions for the RAM Period." Consequently, the treatment of CIP1 an average basis for determining HECO's 2009 rate base not only is consistent with the average test year concept, but also appears to be consistent with how the Joint Proposal would treat Rate Base for the RAM period.

Q. How have you dealt with HECO's updates in your testimony?

A. Where the reasons for HECO's updates were clear and the impacts were clearly quantified and/or confirmed in HECO's responses to DOD IRs, and were within my assigned scope of work, I have reflected the Company's revised amounts in my adjustments on DOD-106 for rate base changes and DOD-111 for net operating income changes. I should caution, however, that reflecting HECO's updates in this manner should not be interpreted or implied as an endorsement or agreement with every aspect of what HECO adjusted in its updates.

II. REVENUE REQUIREMENT/SUMMARY SCHEDULES

Q. What revenue requirement impact is produced by DOD's recommended adjustments?

A. DOD-101 summarizes and presents the estimated impact on revenue requirements resulting from DOD's recommended adjustments to operating income and rate base that have been quantified as of the date of this filing. It also reflects the weighted cost of capital recommended by DOD witness Stephen Hill. Based on DOD's recommended adjustments, HECO has a base rate revenue deficiency of no more than $45.1 million.

Q. Please explain DOD-101, page 1.

A. Column A reproduces in summary form, HECO's updated "base case" request for a revenue increase of $90.666 million "at currently effective rates" from information presented on HECO's T-23 update, Attachment 7 and the underlying workpapers. Column B shows the DOD's adjusted results. Column C shows the dollar impacts of DOD's recommended adjustments to each line item of the revenue requirement formula.

In columns A and B, adjusted rate base on line 1 is multiplied by the recommended rate of return (on line 2) to determine the required amount of net operating income (line 3). The required net operating income (line 3) is compared with the adjusted net operating income (line 4) to determine the income deficiency (line 5). The operating income deficiency (line 5) is then multiplied by the gross revenue conversion factor (line 6) to determine the revenue deficiency (line 7). In column A, line 8 provides for minor reconciling differences to derive HECO's "base case" revenue deficiency amount of $90.666 million from HECO T-23, Attachment 7. Column A reconciles to HECO's revised updated "base case" revenue deficiency at "current effective rates" of $90.666 million from HECO T-23, Attachment 7.

Q. Please explain DOD-101, page 2.

A. This page of the DOD-101 reconciles the revenue deficiency requested by HECO in HECO T-23, Attachment 7 with the revenue deficiency recommended by DOD.

Q. What is presented on DOD-102?

A. This presents the calculation of the gross revenue conversion factor (GRCF). I am recommending a GRCF of 1.7977851. The GRCF is used to convert net operating income amounts into revenue requirement amounts, and is used on DOD-101, page 1, line 6, for this purpose. It is also used on DOD-101, page 2, to convert net operating income adjustments into their revenue requirement equivalent.

Q. Please explain DOD-103.

A. DOD-103 summarizes the adjusted rate base. HECO's original filed amounts from the HECO T-23, Attachment 7 workpapers are shown in Column A. Column B summarizes the DOD adjustments to each rate base component, and column C shows the adjusted results. As shown on DOD-103, the adjusted rate base for HECO is approximately $1.309 billion. This does not reflect an adjustment for cash working capital.

Q. Please explain DOD-104.

A. DOD-104 summarizes the adjusted net operating income. HECO's updated "base case" amounts from HECO T-23, Attachment 7, and the related Company workpapers are shown in Column A. Column B summarizes the DOD adjustments to each operating income component, and column C shows the adjusted results. As shown on DOD-104, the adjusted net operating income for HECO at currently effective rates is $77.7 million.

Q. Please explain DOD-105.

A. DOD-105 summarizes HECO's capital structure and weighted cost of capital in Part I and DOD's recommended capital structure and weighted cost of capital in Part II. DOD's cost of capital recommendations produce an overall weighted cost of capital of 7.85% and are being sponsored by Stephen G. Hill. I calculated the "Pre-Tax Rates" shown in DOD-105, column D. I used such rates for purposes of reconciling the DOD and HECO revenue requirements on DOD-101, page 2.

III. RATE BASE ADJUSTMENTS

Q. Have you prepared an exhibit that summarizes DOD's adjustments to rate base?

A. Yes. These adjustments are shown on DOD-106. The recommended adjustments to rate base are discussed in the same order as they appear on DOD-106.

A. Adjust Rate Base for December 31, 2008 Recorded Amounts

Q. How have you reflected the rate base changes related to the use of actual December 31, 2008 information?

A. DOD-107 shows the adjustment to reduce average 2009 test year rate base by $16.551 million for the use of actual December 31, 2008 recorded information. HECO's update of average test year rate base from its HECO T-23, Attachment 7, had used some estimates for beginning-of-test year amounts. The test year for this HECO rate case is 2009. Information as of December 31, 2008 is now known and should be used for the beginning of test year amounts. HECO's response to DOD-IR-94, supplement March 9, 2009, Attachment 1, provided actual amounts for December 31, 2008. Use of the actual December 31, 2008 information provided in HECO's response to DOD-IR-94 reduces the test year beginning balance by $33.102 million and reduces the average 2009 test year balance by $16.551 million.

Q. Should your reflection of HECO's actual December 31, 2008 amounts as updates to rate base shown on DOD-107 be interpreted as an endorsement of all of HECO's updates?

A. No, it should not. Reflecting the HECO updates in the manner shown on DOD-107 is intended to adjust the starting point of my rate base analysis to reflect the use of actual December 31, 2008 information. Updating HECO's rate base in this manner was administratively efficient and should not be interpreted or implied as an endorsement or agreement with every aspect of what HECO adjusted in its updates or everything included in the December 31, 2008 balances. Rather, it reflects the endorsement of the concept that the revenue requirement for HECO in this case should be based upon a 2009 test year that starts with actual recorded balances on HECO's books at the beginning of the test year.

B. Customer Information System

Q. Please explain the adjustment to rate base for costs related to the Customer Information System ("CIS").

A. In its updated filing HECO had included in average test year rate base $11.392 million for Unamortized System Development Costs. This is shown in

HECO-1117 from the Rate Case Update related to the CIS. The development of the CIS has not gone smoothly, but rather has experienced considerable cost overruns, problems and delays. In response to discovery, including CA-IR-317 through 329, HECO has stated that: "Please see the Company's response to CA-IR-323 which states that, at this time, the HECO Companies believe that it is likely that the CIS project will not be placed into service in 2009. In addition, most of the 2009 test year costs for the CIS project are being removed from the test year." Attachment 1 to HECO's response to CA-IR-323 presented a summary of changes to the HECO 2009 test year due to the delay in the CIS in-service date. This adjustment reduces the 2009 average rate base by $9.557 million, and includes the following components, based on the amounts listed by HECO in its response to CA-IR-323:

Line	Description		Amount
1	Capital Costs	$	(15,474)
2	Unamortized System Development Costs	$	(11,391,500)
3	ADIT associated with the CIS Project	$	1,849,642
	Adjustment to Average Test Year Rate Base	$	(9,557,332)

C. *Cash Working Capital*

Q. What is cash working capital?

A. Cash working capital is the cash needed by the Company to cover its day-to-day operations. If the Company's cash expenditures, on an aggregate basis, precede the cash recovery of expenses, investors must provide cash working capital. In that situation a positive cash working capital requirement exists.

On the other hand, if revenues are typically received prior to when expenditures are made, then ratepayers provide the cash working capital to the utility, and the negative cash working capital allowance is reflected as a reduction to rate base. In this case, the cash working capital requirement is an increase to rate base as investors are essentially supplying these funds.

Q. Does HECO have a positive or negative cash working capital requirement?

A. HECO's filing shows a positive cash working capital requirement. This result implies that, on average, revenues from ratepayers are received after the utility pays the associated expenditures.

Q. Did HECO present a lead/lag study in support of its cash working capital requirement?

A. Yes, HECO provided lead/lag study information to calculate the cash working capital requirement in this case. The Company also provided its lead/lag study calculations with the work papers provided in the case.

Q. Are there concerns regarding how HECO has treated certain items in its cash working capital calculation?

A. Yes. I address such concerns below, and present my recommendation for a revised lag for the O&M Non-Labor payment lag.

Q. Have you comprehensively updated HECO's cash working capital in your presentation?

A. No. The final cash working capital calculation will need to be synchronized with the expenses adopted by the Commission, using the lags adopted by the Commission. Because I am only addressing limited issues with respect to cash working capital, I have not attempted to comprehensively update HECO's cash working capital calculation.

Q. Please explain DOD-109.

A. DOD-109 shows my recommended lag of 33 days for the O&M Non-Labor Payment Lag. HECO's derivation of that lag had applied a zero-day payment lag for payments into the pension trust, included non-cash amortizations at a zero-day payment lag, and applied a lengthy negative payment lag for rate case cost.

1. Pension Payment Lag

Q. Please explain the pension payment lag.

A. HECO's calculation had applied a zero-day payment lag for payments into the pension trust. HECO did not make any contributions into the pension trust in 2008. HECO's response to CA-IR-433(a) and its supplemental response to DOD-IR-101 indicates that HECO will be required to make a contribution to the pension trust in 2009 of $8.218 million in accordance with the Pension Protection Act. In a lead-lag study it is appropriate and necessary to apply a reasonable payment lag to cash payments of expenses. The payment lag for pension expense was a disputed issue in HECO's last rate case. HECO's response to CA-IR-433 suggests that HECO would be making monthly payments into the pension trust in 2009. However, I am not aware of any requirement that HECO make such payments monthly. HECO makes OPEB funding payments quarterly, as described in response to CA-IR-433(b). Based on prior years, HECO has not made payments into the pension trust on an annual basis. For purposes of the current rate case, I believe it would be reasonable to apply a quarterly payment lag to the $8.218 million contribution into the pension trust that HECO indicates it will be required to make in 2009. DOD-109, line 1, reflects a quarterly payment for the cash payment portion of HECO's 2009 pension expense.

2. Non-Cash Amortizations and Accruals

Q. Please explain why non-cash expenses should be removed from the derivation of the cash working capital allowance.

A. Inclusion of non-cash amortizations in a lead-lag study at a zero-day payment lag as HECO has done is generally improper because amortization is a non-cash expense, and the purpose of a lead-lag study is to determine the utility's <u>cash</u> working capital requirement.

Q. In general, how should the payment lag for amortizations be determined for purposes of the cash working capital requirement?

A. This depends upon the purpose of the amortization. If the purpose of the amortization is to adjust an O&M expense to a normalized level for ratemaking purposes, then the normal payment lag applicable for other similar O&M non-labor expense should be applied. If the purpose of the amortization is to include a non-cash expense in the determination of net operating income, it should be excluded from the lead-lag study, similar to the exclusion of non-cash expenses such as depreciation and deferred income taxes. As noted above, because the purpose of the lead-lag study is to measure <u>cash</u> working capital, non-cash expenses are excluded.

Q. How were the amortizations treated for ratemaking purposes in prior cases?

A. This is discussed in HECO's response to DOD-IR-81. The treatment of these items was disputed in HECO's last rate case, Docket No. 2006-0386 (HECO's 2007 test year rate case). A compromise was reached on the ratemaking treatment of such items in a settlement reached in that proceeding. However, as admitted by HECO in its response to CA-IR-431(a): "HECO's reference to the Settlement Letter and the Commission's Interim Decision and Order No. 23749 should not be interpreted as a limitation or restriction on the treatment the Parties may choose to recommend."

Q. How have you adjusted the amortizations listed by HECO on DOD-IR-81?

A. I have removed such items from the derivation of the O&M non-labor payment lag, as shown on DOD-109.

3. Rate Case Expense

Q. How has HECO proposed to treat rate case expense in its lead-lag study?

A. As explained in the response to DOD-IR-81, page 3, HECO proposes to include rate case expense in the lead-lag study at a <u>negative</u> 547-day payment lag.

Q. Do you agree with that treatment?

A. No. Reflecting rate case expense in the determination of cash working capital at a negative 547-day lag is another way, albeit more indirect, of the utility attempting to include rate case expense in rate base to earn a return for its shareholders. Reflecting rate case expense in the lead-lag study at a negative 547-day payment lag would essentially be equivalent to including the unamortized balance of rate case expense in rate base, to earn a return for investors. Unamortized rate case expense should not be included in rate base, either directly or indirectly, by including it in the cash working capital determination at a 547-day negative payment lag. Allowing HECO to earn a rate of return on rate case cost would be contrary to public policy and commission precedent. Rate case expense is a standard cost of doing business for a utility. It is an operating expense. There is no reason that the shareholders should earn a return on rate case expense. Allowing HECO to earn a profit on its rate case expense could also encourage the Company to incur higher amounts of such expense.

Q. How did you reflect rate case expense in the determination of the non-labor O&M expense lag?

A. I have excluded the rate case expense amortization. As explained above, HECO's proposal to include it in the lead-lag study at a 547-day negative payment lag is improper for a number of reasons and should be rejected.

Q. What is your total non-labor O&M payment lag, after reflecting the above adjustments?

A. It is 33 days as shown on DOD-109.

4. Lag for Franchise Royalty Tax

Q. Have HECO's recent responses to discovery raised concerns regarding any other lag calculations in HECO's lead-lag study?

A. Yes. HECO's response to CA-IR-435 raises a concern about HECO's derivation of the lag for revenue-based taxes. Specifically, whereas the PSC tax and PUC fees are computed on billed revenues, the franchise royalty tax is computed on the cash basis. Consequently, it appears that the expense payment lag for franchise royalty tax used by HECO warrants an adjustment.

5. Other Recommendations Concerning Cash Working Capital

Q. Do you have any other recommendations concerning cash working capital?

A. Yes. In Decision and Order ("D&O") No. 8570 (12/12/85) in Docket No. 5081, HECO's test year 1985 rate case, and in D&O 10993 (3/6/91) in HECO's test year 1990 rate case, the Commission addressed the exclusion of non-cash expenses such as depreciation and deferred income tax expense from the calculation of cash working capital. Despite such decisions, HECO states on CA-IR-431 and DOD-IR-81 that its "position" is that <u>all</u> revenues should be included in the revenue collection lag and all payments should be included in the payment lag in the calculation of cash working capital. Given the apparently growing areas of disagreement regarding the appropriate treatment of various items for lead-lag study/cash working capital purposes that have become apparent from some of HECO's recent responses to discovery, I recommend that cash working capital be comprehensively reviewed in

HECO's next rate case. This review should include a re-examination of ratepayer provided funding for other cash expenditures that are included in the determination of HECO's revenue requirement, including interest expense..

D. Accumulated Deferred Income Taxes

Q. Did HECO update its 2009 balance of Accumulated Deferred Income Taxes ("ADIT") for 2009 bonus tax depreciation?

A. No. HECO's response to CA-IR-425(b) states that: "HECO did not update the deferred taxes for 2009, since the application of bonus depreciation for 2009 was only recently enacted."

Q. What do you recommend?

A. ADIT is a significant offset to rate base. Reflecting the impact of 2009 bonus depreciation is expected to increase the end-of-test-year ADIT balance and reduce rate base. During the course of this proceeding, HECO should update its ADIT balance for the impact of 2009 bonus depreciation, and should provide the parties with an updated ADIT balance that reflects this.

IV. NET OPERATING INCOME ADJUSTMENTS

Q. Have you prepared an exhibit which summarizes DOD's adjustments to net operating income?

A. Yes. These adjustments are shown on DOD-111. The recommended adjustments to net operating income are discussed in the same order as they appear on DOD-111.

Q. Do you also show the impact of each adjustment on income tax expense on DOD-111?

A. Yes. The impact of each adjustment on income tax expense is shown on DOD-111, line 21. Income taxes are generally computed using the combined state and federal income tax rate of 38.91% shown on DOD-102 and HECO's workpapers for its T-23 Update, Attachment 7.

A. Customer Information System

Q. Please explain the adjustment to remove Customer Information System costs?

A. As explained above, in conjunction with the corresponding rate base adjustment, in response to discovery, including CA-IR-317 through 329, HECO has stated that: "Please see the Company's response to CA-IR-323 which states that, at this time, the HECO Companies believe that it is likely that the CIS project will not be placed into service in 2009. In addition, most of the 2009 test year costs for the CIS project are being removed from the test year." Attachment 1 to HECO's response to CA-IR-323 presented a summary of changes to the HECO 2009 test year due to the delay in the CIS in-service date. This adjustment reduces operating expenses before income taxes by $4.073 million.

Q. Does the removal of CIS costs from the current rate case totally resolve for ratemaking purposes the issues related to cost overruns relating to this project?

A. No. The adjustment removes the CIS costs from the current rate case. Because the CIS cost is being removed from the current rate case, the issue of specific cost disallowances apparently does not need to be addressed in the instant HECO rate case. However, an issue of whether the project was prudently managed and, consequently, whether the cost overruns incurred by HECO are reasonable and whether they should be charged to ratepayers remains, and may thus need to be addressed in a future proceeding when and if HECO attempts to charge ratepayers for the CIS.

B. General Inflation

Q. Please explain the adjustment to remove general inflation.

A. HECO's 2009 budget included $7.8 million of additional non-labor O&M expenses for "general inflation" which HECO calculated at 2.5%, as explained in the response to DOD-IR-129. HECO relied upon estimates of inflation from January 2008 and May 2008 published by Blue Chip Economic Indicators. More recent information from a March 10, 2009 publication by that same source provided in CA-IR-427 shows an expectation of deflation (i.e., general price decreases) for 2009, as does the January 10, 2009 publication provided in response to DOD-IR-130. Those publications show the 2009 consensus for the Consumer Price Index ("CPI") to be -0.8% and -0.4%, respectively. Additionally, the California Public Utilities Commission ("CPUC"), Division of Ratepayer Advocates ("DRA") publishes a periodic Escalation Memorandum ("Escalation Memo"). Recent DRA Escalation Memos also forecast deflation (negative escalation) for non-labor costs for 2009. I have attached an excerpt from a recent DRA Escalation Memo as DOD-113, page 2. Consequently, the

HECO general inflation adjustment should be removed.

C. *Ward Base Yard Capitalization*

Q. Please explain your adjustment for Ward Base Yard Capitalization.

A. This adjustment is shown on Exhibit DOD-114 and reduces test year expense by $145,000. In response to CA-IR-348(a), HECO indicated that a portion of the Ward Base Yard repairs should be capitalized, rather than expensed. This adjustment removes from 2009 test year expenses the amount to be capitalized.

D. *Vehicle Fuel Cost*

Q. Please explain your adjustment for Vehicle Fuel Cost.

A. This adjustment is shown on DOD-115 and reduces O&M expense by $268,000 to reflect the reduction in vehicle fuel costs. The response to CA-IR-387 reflects estimates of lower 2009 current fuel costs under two alternatives: (1) using current prices as of March 23, 2009; and (2) using three-year average prices. Because of the recession, the use of current fuel prices appears to be a better estimate for 2009 fuel costs.

E. *Expiring Amortization*

Q. Please explain your adjustment for an Expiring Amortization.

A. As explained in HECO's response to CA-IR-418, HECO included in the 2009 test year $2.198 million for an amortization of assets that were retired on September 4, 2004. Including this expiring amortization in the test year would overstate expenses prospectively. Rather than exclude it from the test year as a non-recurring cost, I recommend re-scheduling the amortization of the 2009 amount over two years (approximately HECO's rate case filing period). This would provide full recovery of the remaining unamortized amount over the two-year re-scheduled amortization period, and would prevent the overstatement of rates that would result from the inclusion in operating expenses of an expired amortization. Re-scheduling this amortization reduces test year amortization expense by $825,000 as shown on DOD-116.

F. *Community Service Activities Expense*

Q. Please explain your adjustment for Community Service Activities Expense.

A. HECO has included in 2009 test year expenses $361,000 for Community Service Activities. It is questionable that such expenses are necessary for the provision of safe and reliable electric services. Moreover, such activities tend to promote goodwill for the Company and enhance its image in the community. There is a benefit to shareholders from such discretionary corporate-image-enhancing expenditures. Consequently, an allocation of such costs between shareholders and ratepayers is appropriate. I recommend an equal sharing of such costs. DOD-117 shows the adjustment to allocate 50% or $181,000 of these expenses to HECO shareholders.

G. *Income Taxes – Interest Synchronization*

Q. Please explain the adjustment for interest synchronization.

A. As shown on DOD-118, the interest synchronization adjustment synchronizes the rate base and cost of capital with the tax calculation. It is calculated by applying the DOD's recommended weighted cost of debt to the adjusted rate base for HECO to obtain a synchronized interest deduction for use in the calculation of test year income tax expense. As shown on DOD-118, I applied DOD witness Hill's recommended weighted cost of debt, which is 2.38% and can be found on DOD-105, line 14, to the adjusted rate base amount in order to determine the pro forma interest deduction to be used in calculating income tax expense for the 2009 test year. The combined state and federal income tax rates are applied to the resulting interest deduction difference to determine the amount of adjustment to income tax expense for interest synchronization.

Q. Is the interest synchronization adjustment routinely accepted by utilities and utility regulators as an appropriate and necessary adjustment for ratemaking purposes in the utility rate cases in which you have been involved, especially in recent years?

A. Yes. Utilities and utility regulators routinely accept the interest synchronization adjustment as appropriate and necessary for ratemaking purposes in the utility rate cases in which I and other Larkin & Associates' expert witnesses and rate analysts have been involved. Typically, the interest synchronization adjustment is presented in the utility's initial filing and then is only adjusted, if necessary, for changes to rate base or cost of capital. The interest synchronization method is widely used by other utilities and utility regulatory commissions because it appropriately coordinates the elements of the ratemaking formula and is fair to all parties. In prior HECO rate cases, the DOD urged the Commission to adopt interest synchronization as official policy moving forward because it is a superior method that results in appropriate coordination of the elements of the ratemaking formula (rate base, rate of return, and operating expenses) and because it balances the concerns of all stakeholders in an impartial and equitable way.

Q. Did HECO reflect an interest synchronization adjustment in its filing?

A. Yes. The Commission's D&O No. 24068 adopted the interest synchronization adjustment. HECO's workpapers in the current rate case reflect the application of an interest synchronization adjustment.

Q. If HECO reflected an interest synchronization adjustment in its filing, why is there a need to adjust that?

A. HECO adopted the interest synchronization methodology in its workpapers in the current case. However, my recommended rate base and the weighted cost of debt recommended by DOD witness Stephen Hill differ from the figures used in HECO's interest synchronization calculation. This results in an adjustment to synchronize interest with these other elements of DOD's revenue requirement calculation.

H. Depreciation and Amortization on December 31, 2008 Actual Plant

Q. Please explain the adjustment for Depreciation and Amortization Expense on December 31, 2008 actual plant.

A. Depreciation and Amortization Expense for the 2009 test year should be adjusted consistent with the use of actual December 31, 2008 plant balances in determining average test year rate base. The adjustment is presented on DOD-119, and reduces 2009 expense by $2.198 million.

I. Average Test Year Employees

Q. In previous HECO rate cases including Docket Nos. 04-0113 and 2006-0386 you had recommended an adjustment relating to "open positions" that HECO had included in its requested test year O&M, but which were not filled. Does a similar adjustment appear to be necessary in the current 2009 test year case?

A. Yes. An adjustment relating to "open positions" that HECO had included in its requested test year O&M, but which were not filled appears to be necessary in the current 2009 test year case to adjust for the gradual impact of filling the significant level of "open positions" in HECO's 2009 test year filing. In essence, an adjustment is needed to reflect that:

- HECO had not filled the "open positions" as of January 1, 2009, the beginning of the test year;
- HECO might fill the remaining open positions by December 31, 2009, the end of the test year; and
- A 2009 "average" test year is being used for purposes of determining HECO's revenue requirement in this proceeding.

Using an average of the "open positions" that HECO had not filled at the beginning of the test year, but might fill by the end of the test year, would also be consistent with the use of an "average" test year. Additionally, it would give HECO the benefit of the doubt as to whether all of the "open positions" are really needed or will be filled.

Q. Is it certain that HECO will fill the remaining "open" positions by the end of the test year?

A. No. Thus, while HECO has made some progress in filling "open" positions during 2009, there is no assurance that all of the "open" positions would be filed by December 31, 2009. Clearly, many of the "open" positions upon which HECO has based its estimated test year labor cost projections were <u>not</u> filled at the start of the 2009 test year.

Q. Is an assumption for vacancies resulting from additional turnover incorporated in HECO's forecast?

A. No, it does not appear that a "vacancy" factor was included in HECO's 2009 labor cost projections. Rather, HECO's approach was generally to assume for ratemaking purposes that each "open" position was filled throughout the 2009 test year. However, as would be the case with any large company, one would expect additional vacancies to occur and some time lag between vacancies occurring and the subsequent filling of vacant positions.

Q. Does HECO recognize that an adjustment to its 2009 test year filing is necessary to address the issue of work force vacancies?

A. Apparently, yes. HECO's T-15 Update included an adjustment to reduce labor costs by $1.729 million based on a vacancy rate of 2.37% for budgeted non-production headcount. HECO's derivation of the 2.37% vacancy factor was based on a regression analysis and led HECO to conclude that its work force budgeting accuracy for the 2009 test year was substantially improved over historical experience.

Q. Do you agree with HECO's proposed vacancy factor?

A. No. HECO's proposed vacancy factor is significantly lower than historical experience shows. Moreover, there is concern that HECO's selection of certain data points in its regression analysis determined the good R^2 value in this particular instance, but if other periods were selected, R^2 would be lower, indicating that the predictive validity of the method was questionable.

Q. What vacancy rates has HECO experienced on average for its non-production work force?

A. The following table summarizes vacancy rates at various points in time and on average:

Date	Vacancy Rate
9/30/2006	-8.02%
12/31/2006	-7.30%
3/31/2007	-4.88%
6/30/2007	-2.67%
9/30/2007	-3.66%
12/31/2007	-3.39%
3/31/2008	-3.63%
6/30/2008	-2.35%
7/31/2008	-3.06%
9/30/2008	-4.14%
10/31/2008	-3.23%

Averages	Vacancy Rate
Average of all data points	-4.21%
2007 average (12/31/06 through 12/31/07)	-4.38%
2008 quarterly average, 10/31/08 used in place of 12/31/08 which was not considered by HECO)	-3.35%
Average of all data points from 6/30/2007 through 10/31/08	-3.27%

This information indicates that a vacancy rate of approximately 3.3% is a more representative of historical and recent actual experience.

Q. What adjustment do you recommend for non-production work force vacancies?

A. As shown on DOD-120, I recommend the application of a 3.3% vacancy rate, which reduces labor cost by $2.414 million. This compares with the $1.729 million reduction proposed in HECO's T-15 update and results in an additional reduction to non-production labor cost of $684,000.

J. Pension and OPEB Cost

Q. What amount of pension and Other Post Employment Benefit ("OPEB") cost is reflected in HECO's filing?

A. HECO's filing reflects pension cost of $14.623 million and OPEB cost of $3.853 million, respectively, for a total of $18.476 million.

Q. Did HECO update these costs?

A. In HECO T-13 and in response to data requests such as DOD-IR-104, HECO has indicated that its pension and OPEB costs have increased substantially; however, HECO's Update filing did not include those substantially higher cost levels in recalculating its revenue requirement. HECO's updated amounts are $31.488 million for pension cost and $5.551 million for OPEB costs, for a combined total of $37.039 million.

Q. Does the $31.488 million for pension cost appear to represent a normal, annually recurring level for pension cost?

A. No. This amount is unusually high.

Q. What explanation has HECO provided for the higher pension and OPEB amounts?

A. HECO's supplemental response to DOD-IR-104 provided the following explanation:

" The higher updated pension and postretirement estimates ($31,488,000 in NPPC and $6,941,000 in NPBC) compared to the prior estimates provided in HECO T-13, Exhibits HECO 1302 through HECO-1304 ($14,623,000 in NPPC and $5,224,000 in NPBC) were primarily due to the reduction in the value of plan assets which resulted in an increase in the amortization of the loss, offset by an increase in the discount rate assumption from 6.125% to 6.625% for the pension and to 6.5% for postretirement. In addition, a change in the asset return rate assumption from 8.5% to 8.25% and the lower value of plan assets resulted in a decrease in the expected return component of the NPPC and NPBC. An explanation of the increased pension and postretirement amounts, as provided by Watson Wyatt Worldwide, is included in Attachment 4 of this supplemental response."

Q. How does HECO recover changes in pension and OPEB costs?

A. As explained in the response to DOD-IR-83, since Decision and Order No. 23749 in HECO's last rate case, Docket No. 2006-0386, HECO has been permitted to recover changes in pension and OPEB costs via tracker mechanisms that were adopted in that case. A modified version of these trackers was agreed to in a settlement and was adopted by the Commission.

Q. Do you have concerns about the pension and OPEB trackers?

A. Yes. I have concerns that the existence of these trackers has lessened the incentives on HECO management to hold down costs. HECO's response to DOD-IR-119, for example, states: "There are no plans to change plan provisions in 2009 to hold down pension costs." In response to the question: "Has HECO done anything in 2008 to hold down pension costs?" HECO's response stated: "No." By way of explanation, HECO has indicated that "the factors that determine pension cost are plan provisions, employee demographics, pension fund performance, actuarial assumptions and the methodology for determination of the value of plan assets." HECO's response to DOD-IR-117 indicates that in 2007, 2008 or for 2009, HECO (or its parent HEI) did not hedge any of its exposure of pension fund assets to the stock market downturn: "HECO (or HEI) does not hedge any of its exposure of pension assets to stock market downturns because the companies do not have adequate personnel and expertise to implement a hedging strategy." HECO's response explains further that: "The Plan's Investment Policy allows for the Pension Investment Committee to engage competent professional consultants in the development of the investment policy, determination of appropriate asset mix and/or for the selection, supervision and evaluation of investment managers. Investment managers are given the sole responsibility for all purchase and sale decisions for all investments in accordance with the Investment Policy." In response to CA-IR-243, HECO states, among other things, that: "in light of the financial market conditions in late 2008, it is anticipated that the target liability will exceed the plan assets as of January 1, 2009 ... this is due to a severe drop in the market value of pension assets that is beyond the control of HECO ..."

DOD-IR-118 asked: "With the adoption of a pension tracker in HECO's last base rate case, does HECO view all fluctuations in the net periodic pension cost as being the responsibility of its ratepayers?" HECO's response states that: "The pension tracker incorporates the understanding of all parties that net periodic pension costs, over time, will be recovered through rates. Under the pension tracker, the amount of NPPC included in rates is determined in each rate case and does not change between rate cases.

Management is responsible for managing the pension plan provisions and making informed decisions regarding assumptions and investments; all of which impact the net periodic pension cost, including fluctuations thereto."

Other companies, without pension trackers, have taken proactive steps to help minimize cost, including plan modifications and hedging exposure to poor financial market conditions. The existence of the tracker essentially has shifted responsibility for cost fluctuations onto ratepayers, and may thus have lessened incentives for HECO to take similar actions to help minimize and control costs.

Q. Given the existence of the pension and OPEB trackers, what alternatives exist for addressing the pension and OPEB costs in the current HECO rate case?

A. The rate case treatment of the substantially increased pension and OPEB costs cannot be evaluated in isolation without also considering the impact of the related trackers. As I see, it there are a number of alternatives for rate case treatment of the substantial cost increases, given the existence of the trackers. Options include:

1) Using HECO's originally filed amounts (which HECO has also reflected in its Update revenue requirement calculations).

2) Using the substantially increased pension and OPEB costs for ratemaking purposes

3) Using some other, "normalized" amount of pension and OPEB costs for ratemaking purposes.

There are issues and concerns related to each alternative.

Q. What principle should be applied in selecting the best alternative treatment of pension and OPEB costs in the rate case, given the existence of the trackers?

A. The principle that should be applied is minimizing the overall cost to ratepayers.

Q. Which alternative have you reflected for purposes of calculating HECO's revenue requirement and why?

A. I have reflected the same amounts that HECO used in its original and updated revenue requirement filings. This alternative was mainly selected for simplicity purposes, and also to help prevent the DOD from recommending a higher base rate increase than HECO is requesting. Selecting this alternative, as shown on DOD-121, reflects no net adjustment to pension or OPEB expense from HECO's filing. I am open to considering another alternative for base rate revenue requirement purposes if it can be demonstrated that it reduces the overall cost of HECO's pensions and OPEBs to ratepayers.

K. Normalize Research and Development Expenses

Q. Please explain your adjustment for Research and Development (R&D)[1] Expenses.

A. As shown on DOD-122, this adjustment reduces HECO's estimated 2009 R&D expenses by $790,000 to normalize such expenses. In determining the normalized amount, R&D expenditures represented by HECO's Electric Power Research Institute ("EPRI") dues have been excluded. My allowance for

1 HECO refers to this as "R&D" in its responses.

normalized non-EPRI R&D of $1.533 million is consistent with the average non-EPRI R&D for each of these periods: 2004-2008; 2005-2008; and 2006-2008, as shown on DOD-122.

Q. What other R&D spending does HECO project for the 2009 test year?

A. HECO projects an expense for EPRI of $1.657 million, which I have allowed in full.

Q. Was EPRI expense included in HECO's allowed expenses in Docket No. 04-0113?

A. Yes. A 2005 test year was used in that proceeding. As shown on DOD-122, which summarizes information from CA-IR-482, in 2005 HECO's R&D totaled $3.14 million included approximately $1.529 million for EPRI.

Q. After getting EPRI dues included in rates in the 2005 test year, did HECO actually spend the money on EPRI dues in 2006?

A. No. Per CA-IR-482, EPRI dues for 2005 were approximately $1.529 million As listed in the response to CA-IR-482, HECO's total R&D expense for 2006 was only $1.291, and there was no expense incurred by HECO in 2006 for EPRI dues.

Q. What does this illustrate?

A. This illustrates that the R&D expenses are discretionary, and that HECO will not necessarily spend the amount that it requests be included in rates.

Consequently, HECO should not be granted more than a "normalized" amount of R&D expenses in the test year.

Q. What amount of non-EPRI R&D expense do you recommend, and how does that compare with HECO's request?

A. As shown on DOD-122, I recommend a normalized allowance for non-EPRI R&D of $1.533 million. This is $790,000 lower than HECO's requested amount of $2.323 million.

L. Research and Development Tax Credit

Q. Does HECO receive a tax credit related to its R&D?

A. Yes. HECO receives a tax credit for R&D which HECO calculates on its EPRI dues.

Q. Did HECO reflect the R&D tax credit?

A. No. HECO's response to DOD-IR-92 states that: "Although the Company expects to earn a credit for 2009 (approximately $330,000 less tax effect), the benefit of this credit is not taken into account for the 2009 test year." In response to CA-IR-360, HECO stated, among other things, that: "Upon further review, HECO has changed its position and now proposes that this credit be included in the computation of income tax expense for the test year." Moreover, "HECO will add this credit into the income tax calculation at the next opportunity."

Q. What is the amount of the 2009 R&D tax credit?

A. As shown on DOD-123, the calculation of the credit for 2009 is $215,000, which reduces income tax expense.

M. FUTA Tax Reduction

Q. Please explain the adjustment to payroll tax expense related to Federal Unemployment Tax ("FUTA")?

A. HECO's payroll taxes are reduced as the result of a FUTA tax reduction. However, in its filing, HECO did not reflect that reduction, amounting to approximately $16,000. According to the Company's response to DOD-IR-92, "The expectation is that it will be extended again after the current extension. However, consistent with the treatment of the research activities credit above, the surtax (adjusted for revised employee count) should be excluded from revenue requirements." HECO's response to CA-IR-361(a) shows a FUTA tax reduction of $16,500. HECO's response to CA-IR-361(b) states that: "Upon further review and based on the response to CA-IR-360, HECO does not propose to exclude the FUTA surtax as calculated in a. above." DOD-124 shows the reduction to payroll tax expense of $16,000.

N. International Financial Reporting Standards

Q. Please explain the adjustment to expense for International Financial Reporting Standards ("IFRS").

A. HECO's T-11 update has included $100,000 in consultant expense to study IFRS. HECO would incur no fines in 2009 if this cost were not incurred. The timing of studying IFRS is flexible. Per CA-IR-342(c), HECO does not have a contract or a vendor quote for consulting services at this time. Per CA-IR-342(d), HECO did not allocate any of the $100,000 to HELCO or MECO, even though HELCO and MECO might also be required to convert to IFRS. When this cost is incurred by HECO, appropriate allocations to the affiliates HELCO and MECO should also be made, which would reduce the impact on HECO's ratepayers.

A report from the National Association of Regulatory Utility Commissioners ("NARUC") Staff Subcommittees on Accounting and Finance and on International Relations, dated February 2009, entitled *International Accounting: Why Should U.S. Utility Regulators Care?* was provided in response to CA-IR-479. That report presents a high-level summary of international accounting, how it differs from U.S. accounting. At page 19 of 19, the report recommends that: "Now is the time for utility regulators and the utility industry to begin to understand these potential changes and their ratemaking implications."

It would seem that HECO's internal personnel could study IFRS as part of their normal job responsibilities. HECO's case for needing $100,000 for consultant costs for this in 2009 is weak.

DOD-IR-132(d) asked HECO: "Could the incurrence of this cost be reasonably deferred from 2009 and into some future period?" In response to DOD-IR-132(d), HECO stated: "Based on the recent comments by the new chairman of the SEC, Mary Schapiro, regarding her concerns on the planned transition to IFRS, it is possible that the process for converting to IFRS may not begin in 2009. However, unless the concept of moving to IFRS is completely abandoned, HECO and HEI will need to begin the process, and the costs will be incurred during the period in which the rates from this proceeding will be in effect."

Based on the current status of a transition to IFRS, the lack of a contract, the failure to allocate any of the estimated cost to HELCO or MECO, and the possibility that such transition would be postponed, the incurrence of this cost by HECO could reasonably be deferred. Rather than remove entire cost, I have allowed one-third of HECO's requested amount or $33,000. HECO's request for $100,000 is reduced by $67,000 as shown on DOD-125.

O. Rent Expense

Q. Please explain your adjustment for Rent Expense.

A. As shown on DOD-126, this adjustment reduces HECO's rent expense by $138,000 based on the updated information provided in response to DOD-IR-124 and CA-IR-344.

P. Emission Fees

Q. Please explain your adjustment for Emission Fees.

A. As shown on DOD-127, this adjustment reduces $958,000 amount for 2009 emission fees that was presented in the HECO T-7 Update, to a revised amount of $913,000. As shown on DOD-127, HECO has a pattern of over-projecting for emission fees. The average over-projection was $34,000 for 2004-2008; $67,000 for 2005-2008; and $54,000 for 2006-2008. The reduction of $45,000 should be reflected, and removes a "contingency" which, historically, has contributed to HECO's over-projections of this cost.

Q. Does HECO agree with this adjustment?

A. Yes. HECO's response to CA-IR-298 states, among other things, that: "HECO will remove the 5% contingency amount from the 2009 test year estimate for emission fee. The revised emission fee amount is $912,923 … the emission fee reduction is $45,521 in Other Production Operations non-labor expense."

Q. Does this conclude your direct testimony?

A. Yes, it does.

QUALIFICATIONS OF RALPH C. SMITH

Accomplishments

Mr. Smith's professional credentials include being a Certified Financial Planner™ professional, a licensed Certified Public Accountant and attorney. He functions as project manager on consulting projects involving utility regulation, regulatory policy and ratemaking and utility management. His involvement in public utility regulation has included project management and in-depth analyses of numerous issues involving telephone, electric, gas, and water and sewer utilities.

Mr. Smith has performed work in the field of utility regulation on behalf of industry, public service commission staffs, state attorney generals, municipalities, and consumer groups concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maine, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New Mexico, New York, Nevada, North Dakota, Ohio, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Vermont, Virginia, Washington, Washington DC, West Virginia, Canada, Federal Energy Regulatory Commission and various state and federal courts of law. He has presented expert testimony in regulatory hearings on behalf of utility commission staffs and intervenors on several occasions.

Project manager in Larkin & Associates' review, on behalf of the Georgia Commission Staff, of the budget and planning activities of Georgia Power Company; supervised 13 professionals; coordinated over 200 interviews with Company budget center managers and executives; organized and edited voluminous audit report; presented testimony before the Commission. Functional areas covered included fossil plant O&M, headquarters and district operations, internal audit, legal, affiliated transactions, and responsibility reporting. All of our findings and recommendations were accepted by the Commission.

Key team member in the firm's management audit of the Anchorage Water and Wastewater Utility on behalf of the Alaska Commission Staff, which assessed the effectiveness of the Utility's operations in several areas; responsible for in-depth investigation and report writing in areas involving information systems, finance and accounting, affiliated relationships and transactions, and use of outside contractors. Testified before the Alaska Commission concerning certain areas of the audit report. AWWU concurred with each of Mr. Smith's 40 plus recommendations for improvement.

Co-consultant in the analysis of the issues surrounding gas transportation performed for the law firm of Cravath, Swaine & Moore in conjunction with the case of Reynolds Metals Co. vs. the Columbia Gas System, Inc.; drafted in-depth report concerning the regulatory treatment at both state and federal levels of issues such as flexible pricing and mandatory gas transportation.

Lead consultant and expert witness in the analysis of the rate increase request of the City of Austin - Electric Utility on behalf of the residential consumers. Among the numerous ratemaking issues addressed was the economies of the Utility's employment of outside services; provided both written and oral testimony outlining recommendations and their bases. Most of Mr. Smith's recommendations were adopted by the City Council and Utility in a settlement.

Key team member performing an analysis of the rate stabilization plan submitted by the Southern Bell Telephone & Telegraph Company to the Florida PSC; performed comprehensive analysis of the Company's projections and budgets which were used as the basis for establishing rates.

Lead consultant in analyzing Southwestern Bell Telephone separations in Missouri; sponsored the complex technical analysis and calculations upon which the firm's testimony in that case was based. He has also assisted in analyzing changes in depreciation methodology for setting telephone rates.

Lead consultant in the review of gas cost recovery reconciliation applications of Michigan Gas Utilities Company, Michigan Consolidated Gas Company, and Consumers Power Company. Drafted recommendations regarding the appropriate rate of interest to be applied to any over or under collections and the proper procedures and allocation methodology to be used to distribute any refunds to customer classes.

Lead consultant in the review of Consumers Power Company's gas cost recovery refund plan. Addressed appropriate interest rate and compounding procedures and proper allocation methodology.

Project manager in the review of the request by Central Maine Power Company for an increase in rates. The major area addressed was the propriety of the Company's ratemaking attrition adjustment in relation to its corporate budgets and projections.

Project manager in an engagement designed to address the impacts of the Tax Reform Act of 1986 on gas distribution utility operations of the Northern States Power Company. Analyzed the reduction in the corporate tax rate, uncollectibles reserve, ACRS, unbilled revenues, customer advances, CIAC, and timing of TRA-related impacts associated with the Company's tax liability.

Project manager and expert witness in the determination of the impacts of the Tax Reform Act of 1986 on the operations of Connecticut Natural Gas Company on behalf of the Connecticut Department of Public Utility Control - Prosecutorial Division, Connecticut Attorney General, and Connecticut Department of Consumer Counsel.

Lead Consultant for The Minnesota Department of Public Service ("DPS") to review the Minnesota Incentive Plan ("Incentive Plan") proposal presented by Northwestern Bell Telephone Company ("NWB") doing business as U S West Communications ("USWC"). Objective was to express an opinion as to whether current rates addressed by the plan were appropriate from a Minnesota intrastate revenue requirements and accounting perspective, and to assist in developing recommended modifications to NWB's proposed Plan.

Performed a variety of analytical and review tasks related to our work effort on this project. Obtained and reviewed data and performed other procedures as necessary (1) to obtain an understanding of the Company's Incentive Plan filing package as it relates to rate base, operating income, revenue requirements, and plan operation, and (2) to formulate an opinion concerning the reasonableness of current rates and of amounts included within the Company's Incentive Plan filing. These procedures included requesting and reviewing extensive discovery, visiting the Company's offices to review data, issuing follow-up information requests in many instances, telephone and on-site discussions with Company representatives, and frequent discussions with counsel and DPS Staff assigned to the project.

Lead Consultant in the regulatory analysis of Jersey Central Power & Light Company for the Department of the Public Advocate, Division of Rate Counsel. Tasks performed included on-site review and audit of Company, identification and analysis of specific issues, preparation of data requests, testimony, and cross examination questions. Testified in Hearings.

Assisted the NARUC Committee on Management Analysis with drafting the Consultant Standards for Management Audits.

Presented training seminars covering public utility accounting, tax reform, ratemaking, affiliated transaction auditing, rate case management, and regulatory policy in Maine, Georgia, Kentucky, and Pennsylvania. Seminars were presented to commission staffs and consumer interest groups.

Previous Positions

With Larkin, Chapski and Co., the predecessor firm to Larkin & Associates, was involved primarily in utility regulatory consulting, and also in tax planning and tax research for businesses and individuals, tax return preparation and review, and independent audit, review and preparation of financial statements.

Installed computerized accounting system for a realty management firm.

Education

Bachelor of Science in Administration in Accounting, with distinction, University of Michigan, Dearborn, 1979.

Master of Science in Taxation, Walsh College, Michigan, 1981. Master's thesis dealt with investment tax credit and property tax on various assets.

Juris Doctor, cum laude, Wayne State University Law School, Detroit, Michigan, 1986. Recipient of American Jurisprudence Award for academic excellence.

Continuing education required to maintain CPA license and CFP® certificate.

Passed all parts of CPA examination in first sitting, 1979. Received CPA certificate in 1981 and Certified Financial Planning certificate in 1983. Admitted to Michigan and Federal bars in 1986.

Michigan Bar Association.

American Bar Association, sections on public utility law and taxation.

Partial list of utility cases participated in:

79-228-EL-FAC	Cincinnati Gas & Electric Company (Ohio PUC)
79-231-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
79-535-EL-AIR	East Ohio Gas Company (Ohio PUC)
80-235-EL-FAC	Ohio Edison Company (Ohio PUC)
80-240-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
U-1933*	Tucson Electric Power Company (Arizona Corp. Commission)
U-6794	Michigan Consolidated Gas Co. --16 Refunds (Michigan PSC)
81-0035TP	Southern Bell Telephone Company (Florida PSC)
81-0095TP	General Telephone Company of Florida (Florida PSC)
81-308-EL-EFC	Dayton Power & Light Co.- Fuel Adjustment Clause (Ohio PUC)
810136-EU	Gulf Power Company (Florida PSC)
GR-81-342	Northern States Power Co. -- E-002/Minnesota (Minnesota PUC)
Tr-81-208	Southwestern Bell Telephone Company (Missouri PSC))
U-6949	Detroit Edison Company (Michigan PSC)
8400	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
18328	Alabama Gas Corporation (Alabama PSC)
18416	Alabama Power Company (Alabama PSC)
820100-EU	Florida Power Corporation (Florida PSC)
8624	Kentucky Utilities (Kentucky PSC)
8648	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
U-7236	Detroit Edison - Burlington Northern Refund (Michigan PSC)
U6633-R	Detroit Edison - MRCS Program (Michigan PSC)

U-6797-R	Consumers Power Company -MRCS Program (Michigan PSC)
U-5510-R	Consumers Power Company - Energy conservation Finance Program (Michigan PSC)
82-240E	South Carolina Electric & Gas Company (South Carolina PSC)
7350	Generic Working Capital Hearing (Michigan PSC)
RH-1-83	Westcoast Transmission Co., (National Energy Board of Canada)
820294-TP	Southern Bell Telephone & Telegraph Co. (Florida PSC)
82-165-EL-EFC (Subfile A)	Toledo Edison Company(Ohio PUC)
82-168-EL-EFC	Cleveland Electric Illuminating Company (Ohio PUC)
830012-EU	Tampa Electric Company (Florida PSC)
U-7065	The Detroit Edison Company - Fermi II (Michigan PSC)
8738	Columbia Gas of Kentucky, Inc. (Kentucky PSC)
ER-83-206	Arkansas Power & Light Company (Missouri PSC)
U-4758	The Detroit Edison Company – Refunds (Michigan PSC)
8836	Kentucky American Water Company (Kentucky PSC)
8839	Western Kentucky Gas Company (Kentucky PSC)
83-07-15	Connecticut Light & Power Co. (Connecticut DPU)
81-0485-WS	Palm Coast Utility Corporation (Florida PSC)
U-7650	Consumers Power Co. - Partial and Immediate (Michigan PSC)
83-662	Continental Telephone Company of California, (Nevada PSC)
U-7650	Consumers Power Company – Final (Michigan PSC)
U-6488-R	Detroit Edison Co., FAC & PIPAC Reconciliation (Michigan PSC)
U-15684	Louisiana Power & Light Company (Louisiana PSC)
7395 & U-7397	Campaign Ballot Proposals (Michigan PSC)
820013-WS	Seacoast Utilities (Florida PSC)
U-7660	Detroit Edison Company (Michigan PSC)
83-1039	CP National Corporation (Nevada PSC)
U-7802	Michigan Gas Utilities Company (Michigan PSC)
83-1226	Sierra Pacific Power Company (Nevada PSC)
830465-EI	Florida Power & Light Company (Florida PSC)
U-7777	Michigan Consolidated Gas Company (Michigan PSC)
U-7779	Consumers Power Company (Michigan PSC)
U-7480-R	Michigan Consolidated Gas Company (Michigan PSC)
U-7488-R	Consumers Power Company – Gas (Michigan PSC)
U-7484-R	Michigan Gas Utilities Company (Michigan PSC)
U-7550-R	Detroit Edison Company (Michigan PSC)
U-7477-R**	Indiana & Michigan Electric Company (Michigan PSC)
18978	Continental Telephone Co. of the South Alabama (Alabama PSC)
R-842583	Duquesne Light Company (Pennsylvania PUC)
R-842740	Pennsylvania Power Company (Pennsylvania PUC)
850050-EI	Tampa Electric Company (Florida PSC)
16091	Louisiana Power & Light Company (Louisiana PSC)
19297	Continental Telephone Co. of the South Alabama (Alabama PSC)
76-18788AA &76-18793AA	Detroit Edison - Refund - Appeal of U-4807 (Ingham County, Michigan Circuit Court)
85-53476AA & 85-534785AA	Detroit Edison Refund - Appeal of U-4758 (Ingham County, Michigan Circuit Court)
U-8091/U-8239	Consumers Power Company - Gas Refunds (Michigan PSC)
TR-85-179**	United Telephone Company of Missouri (Missouri PSC)
85-212	Central Maine Power Company (Maine PSC)

ER-85646001 & ER-85647001	New England Power Company (FERC)
850782-EI & 850783-EI	Florida Power & Light Company (Florida PSC)
R-860378	Duquesne Light Company (Pennsylvania PUC)
R-850267	Pennsylvania Power Company (Pennsylvania PUC)
851007-WU & 840419-SU	Florida Cities Water Company (Florida PSC)
G-002/GR-86-160	Northern States Power Company (Minnesota PSC)
7195 (Interim)	Gulf States Utilities Company (Texas PUC)
87-01-03	Connecticut Natural Gas Company (Connecticut PUC))
87-01-02	Southern New England Telephone Company (Connecticut Department of Public Utility Control)
R-860378	Duquesne Light Company Surrebuttal (Pennsylvania PUC)
3673-	Georgia Power Company (Georgia PSC)
29484	Long Island Lighting Co. (New York Dept. of Public Service)
U-8924	Consumers Power Company – Gas (Michigan PSC)
Docket No. 1	Austin Electric Utility (City of Austin, Texas)
Docket E-2, Sub 527	Carolina Power & Light Company (North Carolina PUC)
870853	Pennsylvania Gas and Water Company (Pennsylvania PUC)
880069**	Southern Bell Telephone Company (Florida PSC)
U-1954-88-102 T E-1032-88-102	Citizens Utilities Rural Company, Inc. & Citizens Utilities Company, Kingman Telephone Division (Arizona CC)
89-0033	Illinois Bell Telephone Company (Illinois CC)
U-89-2688-T	Puget Sound Power & Light Company (Washington UTC))
R-891364	Philadelphia Electric Company (Pennsylvania PUC)
F.C. 889	Potomac Electric Power Company (District of Columbia PSC)
Case No. 88/546*	Niagara Mohawk Power Corporation, et al Plaintiffs, v. Gulf+Western, Inc. et al, defendants (Supreme Court County of Onondaga, State of New York)
87-11628*	Duquesne Light Company, et al, plaintiffs, against Gulf+ Western, Inc. et al, defendants (Court of the Common Pleas of Allegheny County, Pennsylvania Civil Division)
890319-EI	Florida Power & Light Company (Florida PSC)
891345-EI	Gulf Power Company (Florida PSC)
ER 8811 0912J	Jersey Central Power & Light Company (BPU)
6531	Hawaiian Electric Company (Hawaii PUCs)
R0901595	Equitable Gas Company (Pennsylvania Consumer Counsel)
90-10	Artesian Water Company (Delaware PSC)
89-12-05	Southern New England Telephone Company (Connecticut PUC)
900329-WS	Southern States Utilities, Inc. (Florida PSC)
90-12-018	Southern California Edison Company (California PUC)
90-E-1185	Long Island Lighting Company (New York DPS)
R-911966	Pennsylvania Gas & Water Company (Pennsylvania PUC)
I.90-07-037, Phase II	(Investigation of OPEBs) Department of the Navy and all Other Federal Executive Agencies (California PUC)
U-1551-90-322	Southwest Gas Corporation (Arizona CC)
U-1656-91-134	Sun City Water Company (Arizona RUCO)
U-2013-91-133	Havasu Water Company (Arizona RUCO)
91-174***	Central Maine Power Company (Department of the Navy and all Other Federal Executive Agencies)
U-1551-89-102 & U-1551-89-103	Southwest Gas Corporation - Rebuttal and PGA Audit (Arizona Corporation Commission)
Docket No. 6998	Hawaiian Electric Company (Hawaii PUC)

TC-91-040A and TC-91-040B	Intrastate Access Charge Methodology, Pool and Rates Local Exchange Carriers Association and South Dakota Independent Telephone Coalition
9911030-WS & 911-67-WS	General Development Utilities - Port Malabar and West Coast Divisions (Florida PSC)
922180	The Peoples Natural Gas Company (Pennsylvania PUC)
7233 and 7243	Hawaiian Nonpension Postretirement Benefits (Hawaiian PUC)
R-00922314 & M-920313C006	Metropolitan Edison Company (Pennsylvania PUC)
R00922428	Pennsylvania American Water Company (Pennsylvania PUC)
E-1032-92-083 & U-1656-92-183	Citizens Utilities Company, Agua Fria Water Division (Arizona Corporation Commission)
92-09-19	Southern New England Telephone Company (Connecticut PUC)
E-1032-92-073	Citizens Utilities Company (Electric Division), (Arizona CC)
UE-92-1262	Puget Sound Power and Light Company (Washington UTC))
92-345	Central Maine Power Company (Maine PUC)
R-932667	Pennsylvania Gas & Water Company (Pennsylvania PUC)
U-93-60**	Matanuska Telephone Association, Inc. (Alaska PUC)
U-93-50**	Anchorage Telephone Utility (Alaska PUC)
U-93-64	PTI Communications (Alaska PUC)
7700	Hawaiian Electric Company, Inc. (Hawaii PUC)
E-1032-93-111 & U-1032-93-193	Citizens Utilities Company - Gas Division (Arizona Corporation Commission
R-00932670	Pennsylvania American Water Company (Pennsylvania PUC)
U-1514-93-169/ E-1032-93-169	Sale of Assets CC&N from Contel of the West, Inc. to Citizens Utilities Company (Arizona Corporation Commission)
7766	Hawaiian Electric Company, Inc. (Hawaii PUC)
93-2006- GA-AIR*	The East Ohio Gas Company (Ohio PUC)
94-E-0334	Consolidated Edison Company (New York DPS)
94-0270	Inter-State Water Company (Illinois Commerce Commission)
94-0097	Citizens Utilities Company, Kauai Electric Division (Hawaii PUC)
PU-314-94-688	Application for Transfer of Local Exchanges (North Dakota PSC)
94-12-005-Phase I	Pacific Gas & Electric Company (California PUC)
R-953297	UGI Utilities, Inc. - Gas Division (Pennsylvania PUC)
95-03-01	Southern New England Telephone Company (Connecticut PUC)
95-0342	Consumer Illinois Water, Kankakee Water District (Illinois CC)
94-996-EL-AIR	Ohio Power Company (Ohio PUC)
95-1000-E	South Carolina Electric & Gas Company (South Carolina PSC)
Non-Docketed Staff Investigation	Citizens Utility Company - Arizona Telephone Operations (Arizona Corporation Commission)
E-1032-95-473	Citizens Utility Co. - Northern Arizona Gas Division (Arizona CC)
E-1032-95-433	Citizens Utility Co. - Arizona Electric Division (Arizona CC)
	Collaborative Ratemaking Process Columbia Gas of Pennsylvania (Pennsylvania PUC)
GR-96-285	Missouri Gas Energy (Missouri PSC)
94-10-45	Southern New England Telephone Company (Connecticut PUC)
A.96-08-001 et al.	California Utilities' Applications to Identify Sunk Costs of Non-Nuclear Generation Assets, & Transition Costs for Electric Utility Restructuring, & Consolidated Proceedings (California PUC)
96-324	Bell Atlantic - Delaware, Inc. (Delaware PSC)
96-08-070, et al.	Pacific Gas & Electric Co., Southern California Edison Co. and San Diego Gas & Electric Company (California PUC)
97-05-12	Connecticut Light & Power (Connecticut PUC)

R-00973953	Application of PECO Energy Company for Approval of its Restructuring Plan Under Section 2806 of the Public Utility Code (Pennsylvania PUC)
97-65	Application of Delmarva Power &Light Co. for Application of a Cost Accounting Manual and a Code of Conduct (Delaware PSC)
16705	Entergy Gulf States, Inc. (Cities Steering Committee)
E-1072-97-067	Southwestern Telephone Co. (Arizona Corporation Commission)
Non-Docketed Staff Investigation	Delaware - Estimate Impact of Universal Services Issues (Delaware PSC)
PU-314-97-12	US West Communications, Inc. Cost Studies (North Dakota PSC)
97-0351	Consumer Illinois Water Company (Illinois CC)
97-8001	Investigation of Issues to be Considered as a Result of Restructuring of Electric Industry (Nevada PSC)
U-0000-94-165	Generic Docket to Consider Competition in the Provision of Retail Electric Service (Arizona Corporation Commission)
98-05-006-Phase I	San Diego Gas & Electric Co., Section 386 costs (California PUC)
9355-U	Georgia Power Company Rate Case (Georgia PUC)
97-12-020 - Phase I	Pacific Gas & Electric Company (California PUC)
U-98-56, U-98-60, U-98-65, U-98-67	Investigation of 1998 Intrastate Access charge filings (Alaska PUC)
(U-99-66, U-99-65, U-99-56, U-99-52)	Investigation of 1999 Intrastate Access Charge filing (Alaska PUC)
Phase II of 97-SCCC-149-GIT	Southwestern Bell Telephone Company Cost Studies (Kansas CC)
PU-314-97-465	US West Universal Service Cost Model (North Dakota PSC)
Non-docketed Assistance	Bell Atlantic - Delaware, Inc., Review of New Telecomm. and Tariff Filings (Delaware PSC)
Contract Dispute	City of Zeeland, MI - Water Contract with the City of Holland, MI (Before an arbitration panel)
Non-docketed Project	City of Danville, IL - Valuation of Water System (Danville, IL)
Non-docketed Project	Village of University Park, IL - Valuation of Water and Sewer System (Village of University Park, Illinois)
E-1032-95-417	Citizens Utility Co., Maricopa Water/Wastewater Companies et al. (Arizona Corporation Commission)
T-1051B-99-0497	Proposed Merger of the Parent Corporation of Qwest Communications Corporation, LCI International Telecom Corp., and US West Communications, Inc. (Arizona CC)
T-01051B-99-0105	US West Communications, Inc. Rate Case (Arizona CC)
A00-07-043	Pacific Gas & Electric - 2001 Attrition (California PUC)
T-01051B-99-0499	US West/Quest Broadband Asset Transfer (Arizona CC)
99-419/420	US West, Inc. Toll and Access Rebalancing (North Dakota PSC)
PU314-99-119	US West, Inc. Residential Rate Increase and Cost Study Review (North Dakota PSC
98-0252	Ameritech - Illinois, Review of Alternative Regulation Plan (Illinois CUB)
00-108	Delmarva Billing System Investigation (Delaware PSC)
U-00-28	Matanuska Telephone Association (Alaska PUC)
Non-Docketed	Management Audit and Market Power Mitigation Analysis of the Merged Gas System Operation of Pacific Enterprises and Enova Corporation (California PUC)
00-11-038	Southern California Edison (California PUC)
00-11-056	Pacific Gas & Electric (California PUC)
00-10-028	The Utility Reform Network for Modification of Resolution E-3527 (California PUC)

98-479	Delmarva Power & Light Application for Approval of its Electric and Fuel Adjustments Costs (Delaware PSC)
99-457	Delaware Electric Cooperative Restructuring Filing (Delaware PSC)
99-582	Delmarva Power & Light dba Conectiv Power Delivery Analysis of Code of Conduct and Cost Accounting Manual (Delaware PSC)
99-03-04	United Illuminating Company Recovery of Stranded Costs (Connecticut OCC)
99-03-36	Connecticut Light & Power (Connecticut OCC)
Civil Action No. 98-1117	West Penn Power Company vs. PA PUC (Pennsylvania PSC)
Case No. 12604	Upper Peninsula Power Company (Michigan AG)
Case No. 12613	Wisconsin Public Service Commission (Michigan AG)
41651	Northern Indiana Public Service Co Overearnings investigation (Indiana UCC)
13605-U	Savannah Electric & Power Company – FCR (Georgia PSC)
14000-U	Georgia Power Company Rate Case/M&S Review (Georgia PSC)
13196-U	Savannah Electric & Power Company Natural Gas Procurement and Risk Management/Hedging Proposal, Docket No. 13196-U (Georgia PSC)
Non-Docketed	Georgia Power Company & Savannah Electric & Power FPR Company Fuel Procurement Audit (Georgia PSC)
Non-Docketed	Transition Costs of Nevada Vertically Integrated Utilities (US Department of Navy)
Application No. 99-01-016, Phase I	Post-Transition Ratemaking Mechanisms for the Electric Industry Restructuring (US Department of Navy)
99-02-05	Connecticut Light & Power (Connecticut OCC)
01-05-19-RE03	Yankee Gas Service Application for a Rate Increase, Phase I-2002-IERM (Connecticut OCC)
G-01551A-00-0309	Southwest Gas Corporation, Application to amend its rate Schedules (Arizona CC)
00-07-043	Pacific Gas & Electric Company Attrition & Application for a rate increase (California PUC)
97-12-020 Phase II	Pacific Gas & Electric Company Rate Case (California PUC)
01-10-10	United Illuminating Company (Connecticut OCC)
13711-U	Georgia Power FCR (Georgia PSC)
02-001	Verizon Delaware § 271(Delaware DPA)
02-BLVT-377-AUD	Blue Valley Telephone Company Audit/General Rate Investigation (Kansas CC)
02-S&TT-390-AUD	S&T Telephone Cooperative Audit/General Rate Investigation (Kansas CC)
01-SFLT-879-AUD	Sunflower Telephone Company Inc., Audit/General Rate Investigation (Kansas CC)
01-BSTT-878-AUD	Bluestem Telephone Company, Inc. Audit/General Rate Investigation (Kansas CC)
P404, 407, 520, 413 426, 427, 430, 421/ CI-00-712	Sherburne County Rural Telephone Company, dba as Connections, Etc. (Minnesota DOC)
U-01-85	ACS of Alaska, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-34	ACS of Anchorage, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-83	ACS of Fairbanks, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)

U-01-87	ACS of the Northland, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
96-324, Phase II	Verizon Delaware, Inc. UNE Rate Filing (Delaware PSC)
03-WHST-503-AUD	Wheat State Telephone Company (Kansas CC)
04-GNBT-130-AUD	Golden Belt Telephone Association (Kansas CC)
Docket 6914	Shoreham Telephone Company, Inc. (Vermont BPU)
Docket No. E-01345A-06-009	Arizona Public Service Company (Arizona Corporation Commission)
Case No. 05-1278-E-PC-PW-42T	Appalachian Power Company and Wheeling Power Company both d/b/a American Electric Power (West Virginia PSC)
Docket No. 05-304	Delmarva Power & Light Company (Delaware PSC)
Docket No. 04-0113	Hawaiian Electric Company (Hawaii PUC)
Case No. U-14347	Consumers Energy Company (Michigan PSC)
Case No. 05-725-EL-UNC	Cincinnati Gas & Electric Company (PUC of Ohio)
Docket No. 21229-U	Savannah Electric & Power Company (Georgia PSC)
Docket No. 19142-U	Georgia Power Company (Georgia PSC)
Docket No. 03-07-01RE01	Connecticut Light & Power Company (CT DPUC)
Docket No. 19042-U	Savannah Electric & Power Company (Georgia PSC)
Docket No. 2004-178-E	South Carolina Electric & Gas Company (South Carolina PSC)
Docket No. 03-07-02	Connecticut Light & Power Company (CT DPUC)
Docket No. EX02060363, *Phases I&II*	*Rockland Electric Company (NJ BPU)*
Docket No. U-00-88	ENSTAR Natural Gas Company and Alaska Pipeline Company (Regulatory Commission of Alaska)
Phase 1-2002 IERM, Docket No. 01-05-19 REO3	Yankee Gas Service (CT DPUC)
Docket No. G-01551A-00-0309	Southwest Gas Corporation (Arizona Corporation Commission)
Docket No. U-02-075	Interior Telephone Company, Inc. (Regulatory Commission of Alaska)
Docket No. 05-SCNT-1048-AUD	South Central Telephone Company (Kansas CC)
Docket No. 05-TRCT-607-KSF	Tri-County Telephone Company (Kansas CC)
Docket No. 05-KOKT-060-AUD	Kan Okla Telephone Company (Kansas CC)
Docket No. 2002-747	Northland Telephone Company of Maine (Maine PUC)
Docket No. 2003-34	Sidney Telephone Company (Maine PUC)
Docket No. 2003-35	Maine Telephone Company (Maine PUC)
Docket No. 2003-36	China Telephone Company (Maine PUC)
Docket No. 2003-37	Standish Telephone Company (Maine PUC)
Docket Nos. U-04-022, U-04-023	Anchorage Water and Wastewater Utility (Regulatory Commission of Alaska)
Case 05-116-U/06-055-U	Entergy Arkansas, Inc. EFC (Arkansas Public Service Commission)
Case 04-137-U	Southwest Power Pool RTO (Arkansas Public Service Commission)
Case No. 7109/7160	Vermont Gas Systems (Department of Public Service)
Case No. ER-2006-0315	Empire District Electric Company (Missouri PSC)
Case No. ER-2006-0314	Kansas City Power & Light Company (Missouri PSC)
Docket No. U-05-043,44	Golden Heart Utilities/College Park Utilities (Regulatory Commission of Alaska)
A-122250F5000	Equitable Resources, Inc. and The Peoples Natural Gas Company, d/b/a Dominion Peoples (Pennsylvania PUC)
E-01345A-05-0816	Arizona Public Service Company (Arizona CC)

Case No. U-14347	Consumers Energy Company (Michigan PSC)
E-01345A-06-009	Arizona Public Service Company (Arizona CC)
05-1278-E-PC-PW-42T	Appalachian Power Company and Wheeling Power Company both d/b/a American Electric Power Co. (West Virginia PSC)
Docket No. 05-304	Delmarva Power & Light Company (Delaware PSC)
Docket No. 04-0113	Hawaiian Electric Company (Hawaii PUC)
05-806-EL-UNC	Cincinnati Gas & Electric Company (Ohio PUC)
Docket No. 21229-U	Savannah Electric & Power Company (Georgia PSC)
U-06-45	Anchorage Water Utility (Regulatory Commission of Alaska)
03-93-EL-ATA, 06-1068-EL-UNC	Duke Energy Ohio (Ohio PUC)
PUE-2006-00065	Appalachian Power Company (Virginia Corporation Commission)
G-04204A-06-0463 et. al	UNS Gas, Inc. (Arizona CC)
Docket No. 2006-0386	Hawaiian Electric Company, Inc (Hawaii PUC)
E-01933A-07-0402	Tucson Electric Power Company (Arizona CC)
G-01551A-07-0504	Southwest Gas Corporation (Arizona CC)
Docket No.UE-072300	Puget Sound Energy, Inc. (Washington UTC)
PUE-2008-00009	Virginia-American Water Company (Virginia SCC)
PUE-2008-00046	Appalachian Power Company (Virginia SCC)
E-01345A-08-0172	Arizona Public Service Company (Arizona CC)
A-2008-2063737	Babcock & Brown Infrastructure Fund North America, LP. and The Peoples Natural Gas Company, d/b/a Dominion Peoples (Pennsylvania PUC)

Exhibits

Accompanying the Direct Testimony of Ralph C. Smith

Number	Description	Pages
	Revenue Requirement Summary Schedules	
DOD-101	Calculation of Revenue Deficiency	2
DOD-102	Gross Revenue Conversion Factor	1
DOD-103	Adjusted Rate Base	1
DOD-104	Adjusted Net Operating Income	1
DOD-105	Capital Structure and Cost Rates	1
	Rate Base Adjustments	
DOD-106	Summary of Adjustments to Rate Base	1
DOD-107	Update Rate Base Beginning Balance to 12/31/08 Actual	1
DOD-108	Remove Customer Information System Cost	1
DOD-109	Cash Working Capital - Other O&M Non-Labor Payment Lag	1
DOD-110	Accumulated Deferred Income Taxes	1
	Net Operating Income Adjustments	
DOD-111	Summary of Adjustments to Net Operating Income	2
DOD-112	Remove Customer Information System Cost	1
DOD-113	Remove General Inflation	2
DOD-114	Ward Base Yard Capitalization	1
DOD-115	Vehicle Fuel Cost	1
DOD-116	Expiring Amortization	1
DOD-117	"Community Service Activities" Expenses	1
DOD-118	Income Taxes - Interest Synchronization	1
DOD-119	Depreciation and Amortization on 12/31/2008 Actual Plant	1
DOD-120	Work Force Vacancies	1
DOD-121	Pension and OPEB Expense	1
DOD-122	Normalize Non-EPRI R&D Expense	1
DOD-123	R&D Tax Credit on EPRI Dues	1
DOD-124	FUTA Tax Expense	1
DOD-125	International Financial Reporting Standards	1
DOD-126	Rent Expense	1
DOD-127	Emission Fees	1
	Total Pages	30
	Total Pages Including Contents Page	31

Hawaiian Electric Company, Inc.
Calculation of Revenue Deficiency
(Thousands of Dollars)
Test Year Ending December 31, 2009

Line No.	Description	Reference	Per HECO (A)	Per DOD (B)	Difference (C)
1	Adjusted rate base at proposed rates	DOD-103	$1,334,958	$ 1,308,850	$ (26,108)
2	Rate of return	DOD-105	8.81%	7.85%	
3	Net operating income required		$ 117,610	$ 102,745	$ (14,865)
4	Adjusted net operating income	DOD-104	$ 67,178	$ 77,662	$ 10,484
5	Net operating income deficiency		$ 50,432	$ 25,083	$ (25,349)
6	Gross revenue conversion factor	DOD-102	1.7977851	1.7977851	
7	Calculated revenue deficiency		$ 90,666	$ 45,093	$ (45,573)
8	Difference, Lines 7 & 9		$ -		
9	Revenue deficiency at current rates		$ 90,666	$ 45,093	$ (45,573)

Notes and Source

Col.A: HECO T-23, Attachment 7 Workpapers

	Revenue Deficiency Components	DOD-102 Portion	Amount ($000)	Revenue Taxes
7.1	PSC Tax & PUC Fees Rates	6.380%	$2,877	Lines 7.1 and 7.2
7.2	Franchise Tax	2.495%	$1,125	$4,002
7.3	Uncollectibles	0.072%	$32	
7.4	Income taxes at composite rate	35.428%	$15,976	
7.5	Net Operating Income	55.624%	$25,083	
7.6	Totals	100.000%	$45,093	

Hawaiian Electric Company, Inc.
Remove Customer Information System Cost
(Thousands of Dollars)
Test Year Ending December 31, 2009

Line No.	Description	Reference	Adjustment Amount	Multiplier	Revenue Requirement Amount
			(A)	(B)	(C)
1	Revenue Requirement-per HECO Filing	DOD-101		Pre-Tax Return Difference	$ 90,666
2	Rate of Return Difference on HECO rate base Before Pro Forma Working Cash	DOD-103	$ 1,335,773	DOD-105 -1.72%	$ (22,975)
3	Subtotal Revenue Requirement				$ 67,691
	Rate Base Adjustments	Sub-Reference:	Reference: DOD-106	Pre-Tax Return DOD-105	
4	Update Rate Base Beginning Balance to 12/31/08 Actual	DOD-107	$ (16,551)	14.12%	$ (2,337)
5	Remove Customer Information System Cost	DOD-108	$ (9,557)	14.12%	$ (1,349)
6	Cash Working Capital - Other O&M Non-Labor Payment Lag	DOD-109	$ -	14.12%	$ -
7	Accumulated Deferred Income Taxes	DOD-110	$ -	14.12%	$ -
8	Subtotal Rate Base Adjustments Before Pro Forma Working Cash		$ (26,108)		$ (3,686)
9	Change in Working Cash at Proposed Rates	N/A		15.84%	$ -
10	Adjusted Rate Base		$ 1,309,665		$ (3,686)
11	Adjusted Net Operating Income - per HECO	DOD-101 DOD-104	$ 67,178		
	Net Operating Income Adjustments	Sub-Reference:	Reference: DOD-111	GRCF DOD-102	
12	Remove Customer Information System Cost	DOD-112	$ 2,488	1.7977851	$ (4,473)
13	Remove General Inflation	DOD-113	$ 4,758	1.7977851	$ (8,554)
14	Ward Base Yard Capitalization	DOD-114	$ 89	1.7977851	$ (160)
15	Vehicle Fuel Cost	DOD-115	$ 164	1.7977851	$ (295)
16	Expiring Amortization	DOD-116	$ 504	1.7977851	$ (906)
17	"Community Service Activities" Expenses	DOD-117	$ 111	1.7977851	$ (200)
18	Income Taxes - Interest Synchronization	DOD-118	$ (250)	1.7977851	$ 449
19	Depreciation and Amortization on 12/31/2008 Actual Plant	DOD-119	$ 1,343	1.7977851	$ (2,414)
20	Work Force Vacancies	DOD-120	$ 418	1.7977851	$ (751)
21	Pension and OPEB Expense	DOD-121	$ -	1.7977851	$ -
22	Normalize Non-EPRI R&D Expense	DOD-122	$ 482	1.7977851	$ (867)
23	R&D Tax Credit on EPRI Dues	DOD-123	$ 215	1.7977851	$ (387)
24	FUTA Tax Expense	DOD-124	$ 10	1.7977851	$ (18)
25	International Financial Reporting Standards	DOD-125	$ 41	1.7977851	$ (74)
26	Rent Expense	DOD-126	$ 84	1.7977851	$ (151)
27	Emission Fees	DOD-127	$ 27	1.7977851	$ (49)
28	Net Operating Income Adjustments		$ 10,484		$ (18,850)
29	Adjusted Net Operating Income		$ 77,662		
30	Reconciled Revenue Requirement				$ 45,155
31	Unreconciled Difference				$ (62)
32	Recommended Revenue Requirement	DOD-101, page 1			$ 45,093

Hawaiian Electric Company, Inc.
Gross Revenue Conversion Factor
Test Year Ending December 31, 2009
(Thousands of Dollars)

Line No.	Description		Per HECO Dollar Amount (A)	Reference
1	Operating revenue increase	$	90,552	[A]
2	Other Operating Revenue	$	114	[A]
3	Total Revenue	$	90,666	[A]
4	Uncollectibles	$	(65)	[A]
5	Less: Revenue Taxes and Uncollectibles:	$	90,601	[A]
6	Public Service Tax			[A]
7	PUC Fees			[A]
8	Public Service Tax and PUC Fees	$	(5,785)	[A]
9	Franchise Tax	$	(2,262)	[A] & [C]
10	Subtotal Revenue Taxes and Uncollectibles	$	(8,047)	
11	Taxable income for ratemaking	$	82,554	Line 5 + Line 10
12	Income taxes at composite rate	$	(32,121)	-38.9098%
13	Net Operating Income	$	50,433	
14	Operating Income Divisor [L.13 / L.3]		0.55625	
15	Rounding		(0.00001)	
16	**HECO proposed Operating Income Divisor**		**0.55624**	
17	**Gross revenue conversion factor**		**1.7977851**	Line 1 / Line 8

Notes

[A]	HECO T-23, Attachment 7 Excel W/P			
[B]	HECO proposed Operating Income Divisor		0.55624	[A]
	Equivalent gross revenue conversion factor		1.797785129	1 / [B]
[C]	Franchise Tax:			
	Line 1, Operating Revenue	$	90,552	
	Line 4, Uncollectibles	$	(65)	
	Subject to Franchise Tax	$	90,487	
	Franchise Tax Rate		0.02500	
	Franchise Tax	$	2,262	
	Factor after Uncollectibles		0.02498	
[D]	CALCULATIONS OF COMPOSITE INCOME TAX RATE:			
	State Tax Rate		6.0150%	
	Federal Tax Rate		35.0000%	
	Federal Tax Effect on State Tax		-2.1053%	
	COMPOSITE INCOME TAX RATE		38.9098%	
[E]	SUMMARY OF HECO'S CALCULATION			
	Revenue			
	PSC Tax & PUC Fees Rates adjusted for Bad Debt		0.063804	
	Franchise Tax adjusted for Change in Oth Oper Rev and Bad Debt		0.024951	
	Bad Debt Rate adjusted for Change in Oth Oper Rev		0.000718	
	Revenue Tax and Bad Debt rate		0.089473	
	Rev Tax & Bad Debt Reciprocal			
	Composite Income Tax Rate		0.389098	
	OPERATING INCOME DIVISOR			
[F]	REVENUE DEFICIENCY COMPONENTS			
	PSC Tax & PUC Fees Rates		0.06380	
	Franchise Tax		0.02495	
	Uncollectibles		0.00072	
	Income taxes at composite rate		0.35428	
	Net Operating Income		0.55624	
	Totals		1.00000	

Hawaiian Electric Company, Inc.
Adjusted Rate Base
Test Year Ending December 31, 2009

Line No.	Description	HECO T-23 Attachment 7 (A)	DOD Adjustments (B)	DOD Adjusted (C)
	INVESTMENT IN ASSETS SERVING CUSTOMERS			
1	Net Plant In Service	$ 1,474,183	$ (3,856)	$ 1,470,328
2	Property Held for Future Use	$ 2,331	$ -	$ 2,331
3	Fuel Inventory	$ 82,683	$ (13,303)	$ 69,380
4	Materials & Supplies	$ 16,015	$ 188	$ 16,203
5	Unamortized Net SFAS 109 Regulatory Asset	$ 60,524	$ (144)	$ 60,380
6	Unamortized System Development Costs	$ 17,644	$ (11,334)	$ 6,310
7	Unamortized DSG Regulatory Asset	$ 3,183	$ -	$ 3,183
8	ARO Regulatory Asset	$ 13	$ (3)	$ 11
	FUNDS FROM NON-INVESTORS			
9	Unamortized CIAC	$ (181,756)	$ 714	$ (181,043)
10	Customer Advances	$ (848)	$ (30)	$ (878)
11	Customer Deposits	$ (8,244)	$ (147)	$ (8,391)
12	Accumulated Deferred Income Taxes	$ (132,671)	$ 1,716	$ (130,956)
13	Unamortized ITC & PV Tax Credit	$ (33,838)	$ 81	$ (33,758)
14	Unamortized Gain on Sales	$ (1,055)	$ 10	$ (1,046)
15	Pension Liability	$ (2,746)	$ -	$ (2,746)
16	OPEB Liability	$ (700)	$ -	$ (700)
17	Rate base before Working Cash	$ 1,294,718	$ (26,108)	$ 1,268,610
18	Working Cash (at present rates)	$ 41,055		$ 41,055
19	Rate Base at Present Rates	$ 1,335,773	$ (26,108)	$ 1,309,665
20	Working Cash (at proposed rates)	$ (815)		$ (815)
21	**Rate Base at Proposed Rates**	$ 1,334,958	$ (26,108)	$ 1,308,850

Notes and Source

Col.A: HECO T-23, Attachment 7
Col.B: DOD-106
Col C: Col.A + Col.B

Hawaiian Electric Company, Inc.
Adjusted Net Operating Income
(Thousands of Dollars)
Test Year Ending December 31, 2009

Line No.	Description	Per HECO (A)	DOD Adjustments (B)	Per DOD (C)
1	Electric Sales Revenue	$1,861,751	$ -	$ 1,861,751
2	Other Operating Revenue	$ 4,487	$ -	$ 4,487
3	Gain on Sale of Land	$ 615	$ -	$ 615
4	TOTAL OPERATING REVENUES	$1,866,853	$ -	$ 1,866,853
5	Fuel	$ 816,654	$ -	$ 816,654
6	Purchased Power	$ 477,055	$ -	$ 477,055
7	Production	$ 83,567	$ (117)	$ 83,450
8	Transmission	$ 13,930	$ (2,283)	$ 11,647
9	Distribution	$ 30,515	$ (5,775)	$ 24,740
10	Customer Accounts	$ 16,297	$ (4,183)	$ 12,114
11	Allowance for Uncollectibles	$ 1,339	$ -	$ 1,339
12	Customer Service	$ 6,997	$ (230)	$ 6,767
13	Administration and General	$ 77,719	$ (1,574)	$ 76,145
14	Operation and Maintenance	$1,524,073	$ (14,162)	$ 1,509,911
15	Depreciation and Amortization	$ 82,966	$ (3,023)	$ 79,943
16	Amortization of State ITC	$ (1,453)	$ -	$ (1,453)
17	Taxes Other Than Income	$ 172,867	$ (34)	$ 172,833
18	Interest on Customer Deposits	$ 479	$ -	$ 479
19	Income Taxes	$ 20,743	$ 6,735	$ 27,478
20	TOTAL OPERATING EXPENSES	$1,799,675	$ (10,484)	$ 1,789,191
21	**NET OPERATING INCOME**	**$ 67,178**	**$ 10,484**	**$ 77,662**

Notes and Source

Col.A: HECO Excel file workpapers for HECO T-23, Attachment 7
Col.B: DOD-111
Col.C: Col.A + Col.B

Hawaiian Electric Company, Inc.
Capital Structure and Cost Rates
Test Year Ending December 31, 2009

Exhibit DOD-105
Docket No. 2008-0083

Line No.	Description	Cost Rate (A)	Capital Ratio (B)	**Weighted Cost** (A) x (B) (C)	Pre-Tax Return (D)
	I. Per HECO (HECO-2001)				
1	Short Term Debt	3.25%	1.49%	0.05%	0.09%
2	Long Term Debt	5.75%	38.27%	2.20%	3.96%
3	Hybrid Securities	7.41%	1.89%	0.14%	0.25%
4	Preferred Stock	7.62%	4.05%	0.31%	0.56%
5	Common Equity	11.25%	54.30%	6.11%	10.98%
6	Total		100.00%	**8.81%**	15.84%
	II. Per DOD (Stephen G. Hill, DOD-217)				
7	Short Term Debt	2.50%	1.49%	0.04%	0.07%
8	Long Term Debt	5.75%	38.27%	2.20%	3.96%
9	Hybrid Securities	7.41%	1.89%	0.14%	0.25%
10	Preferred Stock	7.62%	4.05%	0.31%	0.56%
11	Common Equity	9.50%	54.30%	5.16%	9.28%
12	Total		100.00%	**7.85%**	14.12%
13	Difference			-0.96%	-1.72%
14	Weighted Cost of Debt	Sum of Lines 7-9		2.38%	

Notes

		GRCF	Reference
Col.D:	Pre-Tax Return computed using GRCF	1.797785	DOD-102

Hawaiian Electric Company, Inc.
Summary of Adjustments to Rate Base
(Thousands of Dollars)
Test Year Ending December 31, 2009

Line No.	Description	DOD Adjustments	Update Rate Base Beginning Balance to 12/31/08 Actual	Remove Customer Information System Cost	Cash Working Capital - Other O&M Non-Labor Payment Lag	Accumulated Deferred Income Taxes
			DOD-107	DOD-108	DOD-109	DOD-110
	INVESTMENT IN ASSETS SERVING CUSTOMERS					
1	Net Plant In Service	$ (3,856)	$ (3,841)	$ (15)		
2	Property Held for Future Use	$ -	$ -			
3	Fuel Inventory	$ (13,303)	$ (13,303)			
4	Materials & Supplies	$ 188	$ 188			
5	Unamortized Net SFAS 109 Regulatory Asset	$ (144)	$ (144)			
6	Unamortized System Development Costs	$ (11,334)	$ 58	$ (11,392)		
7	Unamortized DSG Regulatory Asset	$ -	$ -			
8	ARO Regulatory Asset	$ (3)	$ (3)			
	FUNDS FROM NON-INVESTORS	$ -				
9	Unamortized CIAC	$ 714	$ 714			
10	Customer Advances	$ (30)	$ (30)			
11	Customer Deposits	$ (147)	$ (147)			
12	Accumulated Deferred Income Taxes	$ 1,716	$ (135)	$ 1,850		
13	Unamortized ITC & PV Tax Credit	$ 81	$ 81			
14	Unamortized Gain on Sales	$ 10	$ 10			
15	Pension Liability	$ -	$ -			
16	OPEB Liability	$ -	$ -			
17	Rate base before Working Cash	$ (26,108)	$ (16,551)	$ (9,557)	$ -	$ -
18	Working Cash (at present rates)					
19	Rate Base at Present Rates	$ (26,108)	$ (16,551)	$ (9,557)	$ -	$ -
20	Working Cash (at proposed rates)					
21	**Rate Base at Proposed Rates**	$ (26,108)	$ (16,551)	$ (9,557)	$ -	$ -

Notes and Source

See referenced exhibit for each adjustment

Hawaiian Electric Company, Inc.
Adjusted Rate Base
Test Year Ending December 31, 2009
Update Beginning Balance to 12/31/2008 Recorded
(Thousands of Dollars)

Line No.	Description	Beginning Balance	End of Year Balance	Average Balance	Update Beginning Balance to 12/31/2008 Recorded: Recorded 12/31/2008	Adjustment To Beginning Balance	Adjustment To Average Balance	Adjusted Average Balance
	Investments in Assets Serving Customers	(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	Net Cost of Plant in Service	1,373,259	1,575,107	1,474,183	1,365,578	-7,681	-3,841	1,470,343
2	Property Held for Future Use	2,331	2,331	2,331	2,331	0	0	2,331
3	Fuel Inventory	80,152	85,214	82,683	53,546	-26,606	-13,303	69,380
4	Materials & Supplies Inventories	16,015	16,015	16,015	16,391	376	188	16,203
5	Unamort. Net SFAS 109 Reg. Asset	58,041	63,006	60,524	57,753	-288	-144	60,380
6	Pension Reg Asset	0	0	0		0	0	0
7	OPEB Reg Asset	0	0	0		0	0	0
8	(Unused 1-OPEB Reg Asset - FAS 158)	0	0	0		0	0	0
9	Unamort Sys Dev Costs	4,568	30,719	17,644	4,684	116	58	17,702
10	RO Pipeline Reg Asset	0	6,366	3,183	0	0	0	3,183
11	ARO Reg Asset	13	12	13	8	-5	-3	11
12	Total Investments in Assets	1,534,379	1,778,770	1,656,576	1,500,291	-34,088	-17,044	1,639,532
	Funds From Non-Investors							
13	Unamortized CIAC	180,184	183,327	181,756	178,757	-1,427	-714	181,043
14	Customer Advances	888	807	848	947	59	30	878
15	Customer Deposits	7,907	8,581	8,244	8,200	293	147	8,391
16	Accumulated Def. Income Taxes	132,241	133,100	132,671	132,510	269	135	132,806
17	Unamort State ITC (Gross)	30,264	37,411	33,838	30,103	-161	-81	33,758
18	Unamortized Gain on Sale	1,364	746	1,055	1,345	-19	-10	1,046
19	Pension Reg Liability	3,051	2,441	2,746	3,051	0	0	2,746
20	OPEB Reg Liability	777	622	700	777	0	0	700
21	Total Deductions	356,676	367,035	361,858	355,690	-986	-493	361,365
22	Difference	1,177,703	1,411,735	1,294,718	1,144,601	-33,102	-16,551	1,278,167
23	Working Cash at Current Effective Rates			41,055				
24	Rate Base at Current Effective Rates			1,335,773				
25	Change in Rate Base - Working Cash			(815)				
26	Rate Base at Proposed Rates			1,334,958				

Notes and Source
Cols. A-C: HECO T-23, Attachment 7
Col D: DOD-IR-94, Attachment 1, Recorded 12/31/08
HECO revised its response to DOD-IR-94 on March 4 and supplemented it on March 9, which changed the 12/31/2008 balance for these items:

		3/2/2009 Response	3/4/2009 Response	3/9/2009 Supplement	Difference
L 11	ARO Reg Asset	13	8	8	(5)
L 18	Unamortized Gain on Sale	1,340	1,345	1,345	5

Col E: Col. D - Col. A
Col F: Col. E /2
Col G: Col C + Col. F
Lines 23-26: Working Cash presented by HECO is not revised on this exhibit.

Hawaiian Electric Company, Inc.
Remove Customer Information System Cost
(Thousands of Dollars)
Test Year Ending December 31, 2009

DOD-108
Docket No. 2008-0083
Page 1 of 1

Line No.	Description		Amount	Reference
1	Capital Costs	$	(15)	[A]
2	Unamortized System Development Costs	$	(11,392)	[A]
3	ADIT associated with the CIS Project	$	1,850	[A]
3	Adjustment to Average Test Year Rate Base	$	(9,557)	

Notes and Source

[A] CA-IR-323, Attachment 1

Line	Description	Test Year Expense ($000's) Note A	% of Total	Total Payment Lag Days	Reference	Weighted Average
	I. Cash Payments					
1	Pension Expense cash payment[1]	$ 8,218	6.1%	45.6	Note A and Note 1	3 days
2	OPEB Expense[2]	$ 3,815	2.8%	66.3	Note A	2 days
3	Emission Fees[7]	$ 958	0.7%	252.0	Note A	2 days
4	EPRI Dues[8]	$ 1,657	1.2%	-3.4	Note A	0 days
5	Other Non-Labor O&M[9]	$ 119,259	89.1%	30.3	Note A	27 days
6	Subtotal Cash Payments	$ 133,907	100.0%			
7	O&M Non-Labor Payment Lag					33 days
	II. Non-Cash Amortizations and Accruals					
8	Pension Expense non-cash accrual[1]	$ 2,603			Exclude non-cash accrual	N/A
9	Pension Regulatory Liability amort.[3]	$ (610)			Exclude non-cash amortization	N/A
10	OPEB Regulatory Liability amort.[4]	$ (155)			Exclude non-cash amortization	N/A
11	System Devel. Costs Amortization[5]	$ 1,610			Exclude non-cash amortization	N/A
12	Regulatory Commission Expense[6]	$ 440			Exclude for reasons stated in testimony	N/A
13	Waiau Water Well Amortization[7]	$ 295			Exclude non-cash amortization	N/A
14	Subtotal Non-Cash Amortizations	$ 4,183				
15	Total	$ 138,091				

Notes and Source

NOTE: Totals may not add exactly due to rounding.

[A] DOD-IR-81 and CA-IR-432

[1] Pension expense estimate based on 2009 Pension Accrual of $14,623k (per HECO-1303) x 74% (based on 2007 % of Employee Benefits charged to O&M expense).

2009 payment	$8,218	CA-IR-433
Expense accrual beyond payment	$2,603	
Total	$10,821	

Quarterly payment used for 2009 contributions into the pension trust

[2] OPEB expense estimate based on 2009 OPEB expense of $5,155k (per HECO-1301) x 74% (based on 2007 % of Employee Benefits charged to O&M expense). Includes $1,302k of SFAS 106 Reg. Asset amortization.

[3] Per HECO-1124.

[4] Per HECO-1125.

[5] Per HECO-1117.

[6] Per HECO-1403.

[7] Per HECO T-7.

[8] Per HECO-1406

[9] Other Non-Labor O&M = Total O&M Non-Labor expense of $138,091k, less other items noted above.

Hawaiian Electric Company, Inc.
Accumulated Deferred Income Taxes
(Thousands of Dollars)
Test Year Ending December 31, 2009

Line No.	Description	12/31/2008 Amount	12/31/2009 Amount	Average
		(A)	(B)	(C)

HECO's 2009 ADIT balance needs to be updated for the impact of 2009 bonus tax depreciation. Because of the complexity involved, HECO will need to provide this information.

Notes and Source

CA-IR-425(b)

Hawaiian Electric Company, Inc.
Adjusted Net Operating Income
(Thousands of Dollars)
Test Year Ending December 31, 2009

Line No.	Description	DOD Adjustments	Remove Customer Information System Cost DOD-112	Remove General Inflation DOD-113	Ward Base Yard Capitalization DOD-114	Vehicle Fuel Cost DOD-115	Expiring Amortization DOD-116	"Community Service Activities" Expenses DOD-117	Income Taxes - Interest Synchronization DOD-118	Depreciation and Amortization on 12/31/2008 Actual Plant DOD-119
1	Electric Sales Revenue	-								
2	Other Operating Revenue	-								
3	Gain on Sale of Land	-								
4	TOTAL OPERATING REVENUES	-	-	-	-	-	-	-	-	
5	Fuel	-								
6	Purchased Power	-								
7	Production	(117)		(32)		(40)				
8	Transmission	(2,283)		(2,154)		(62)				
9	Distribution	(5,775)		(5,489)		(118)				
10	Customer Accounts	(4,183)	(4,055)	-		(22)				
11	Allowance for Uncollectibles	-								
12	Customer Service	(230)		-		(3)		(181)		
13	Administration and General	(1,574)		(114)	(145)	(23)				
14	Gen Excise Tax Rate Incr Adj	-								
15	Operation and Maintenance	(14,162)	(4,055)	(7,789)	(145)	(268)	-	(181)	-	-
16	Depreciation and Amortization	(3,023)					(825)			(2,198)
17	Amortization of State ITC	-								
18	Taxes Other Than Income	(34)	(18)							
19	Interest on Customer Deposits	-								
20	Expense Before Income Taxes	(17,219)	(4,073)	(7,789)	(145)	(268)	(825)	(181)	-	(2,198)
21	Income Taxes	6,735	1,585	3,031	56	104	321	70	250	855
22	TOTAL OPERATING EXPENSES	(10,484)	(2,488)	(4,758)	(89)	(164)	(504)	(111)	250	(1,343)
23	**NET OPERATING INCOME**	10,484	2,488	4,758	89	164	504	111	(250)	1,343

Notes and Source

Line 21: Combined Income Tax Rate (DOD-102) 38.91%

Hawaiian Electric Company, Inc.
Adjusted Net Operating Income
(Thousands of Dollars)
Test Year Ending December 31, 2009

DOD-111
Docket No. 2008-0083

Line No.	Description	Work Force Vacancies DOD-120	Pension and OPEB Expense DOD-121	Normalize Non-EPRI R&D Expense DOD-122	R&D Tax Credit on EPRI Dues DOD-123	FUTA Tax Expense DOD-124	International Financial Reporting Standards DOD-125	Rent Expense DOD-126	Emission Fees DOD-127
1	Electric Sales Revenue								
2	Other Operating Revenue								
3	Gain on Sale of Land								
4	TOTAL OPERATING REVENUES			$ -	$ -	$ -	$ -	$ -	$ -
5	Fuel								
6	Purchased Power								
7	Production								$ (45)
8	Transmission	$ (67)							
9	Distribution	$ (168)							
10	Customer Accounts	$ (106)							
11	Allowance for Uncollectibles								
12	Customer Service	$ (46)							
13	Administration and General	$ (297)	$ -	$ (790)			$ (67)	$ (138)	
14	Gen Excise Tax Rate Incr Adj								
15	Operation and Maintenance	$ (684)	$ -	$ (790)	$ -	$ -	$ (67)	$ (138)	$ (45)
16	Depreciation and Amortization								
17	Amortization of State ITC								
18	Taxes Other Than Income					$ (16)			
19	Interest on Customer Deposits								
20	Expense Before Income Taxes	$ (684)	$ -	$ (790)	$ -	$ (16)	$ (67)	$ (138)	$ (45)
21	Income Taxes	$ 266	$ -	$ 308	$ (215)	$ 6	$ 26	$ 54	$ 18
22	TOTAL OPERATING EXPENSES	$ (418)	$ -	$ (482)	$ (215)	$ (10)	$ (41)	$ (84)	$ (27)
23	**NET OPERATING INCOME**	$ 418	$ -	$ 482	$ 215	$ 10	$ 41	$ 84	$ 27

Notes and Source
Line 21. Combined Income Tax Rate (DOD-102)

Line No.	Description		Amount	Reference
	I. Adjustment to Remove Customer Information System Costs			
1	Project Expenses	$	(2,913)	CA-IR-323, Attachment 1
2	Non-Project Expenses	$	(1,751)	CA-IR-323, Attachment 1
3	Add Back for Labor Expenses	$	609	CA-IR-323, Attachment 1
4	Adjustment to Test Year O&M Expenses	$	(4,055)	
5	Adjustment to Taxes Other Than Income Taxes	$	(18)	CA-IR-323, Attachment 1
6	**Total Adjustment to Pre-Tax Operating Expenses**	$	(4,073)	
	II. Summary of Changes to the HECO 2009 Test Year Due to the Delay in the Customer Information System ("CIS") In-Service Date			
	Per CA-IR-323, Attachment 1			
	PROJECT EXPENSES:			
7	1 Reversal of Project Expenses - Revised HECO-907 (line 29)		($1,506,519)	
8	Reversal of Amortization - Revised HECO-907 (line 30)		($976,941)	
	2 Expense reduction due to employees remaining on the CIS development team for the months of June through December (recorded to Deferred Expenses)			
9	Productive Expense		($293,288)	
10	Non-Productive Expense		($42,990)	
11	Emp Benefit		($93,116)	
12	Total Project Expenses		($2,912,854)	
	NON-PROJECT EXPENSES (Including new Bill Print, IVR, IWR systems/processes):			
13	1 Reversal of Post Go-Live Non-Project expenses		($1,353,565)	
14	2 Additional expenses for Standard Register Forms		$60,468	
15	3 Net Reduction of ITS Costs		($458,094)	
16	Total Non-Project Expenses		($1,751,191)	
	ADD BACK FOR LABOR EXPENSES:			
17	1 Productive Expense		$280,658	
18	Non-Productive Expense		$41,559	
19	All other On-Cost		$287,193	
20	Total add back to test year		$609,410	
21	**TOTAL NET CHANGE TO TEST YEAR EXPENSES**		($4,054,635)	
	TOTAL NET CHANGE TO TAXES OTHER THAN INCOME TAXES			
22	Payroll Tax changes associated with labor in O&M expenses.		($18,375)	

Hawaiian Electric Company, Inc.
Remove General Inflation
(Thousands of Dollars)
Test Year Ending December 31, 2009

Exhibit DOD-113
Docket No. 2008-0083

Line No.	Description	HECO As-Filed Amount (A)	HEC Update Amount (B)	Difference (C)	DOD Adjusted (D)	DOD Adjustment Before A&G Transfer (E)	A&G Transfer (F)	DOD Adjustment After A&G Transfer (G)
	I. DETAIL							
1	Production Operations	$ -			$ -	$ -		$ -
2	Production Maintenance	$ 32			$ -	$ (32)		$ (32)
3	Transmission Operations	$ 370			$ -	$ (370)		$ (370)
4	Transmission Maintenance	$ 1,784			$ -	$ (1,784)		$ (1,784)
5	Distribution Operations	$ 432			$ -	$ (432)		$ (432)
6	Distribution Maintenance	$ 5,057			$ -	$ (5,057)		$ (5,057)
7	Customer Accounts	$ -			$ -	$ -		$ -
8	Customer Service	$ -			$ -	$ -		$ -
9	A&G Operations	$ 109			$ -	$ (109)	$ 11	$ (98)
10	A&G Maintenance	$ 18			$ -	$ (18)	$ 2	$ (16)
11	Total O&M - Non-Labor	$ 7,802	$ -	$ -	$ -	$ (7,802)	$ 13	$ (7,789)
	II. SUMMARY							
12	Production	$ 32				$ (32)		$ (32)
13	Transmission	$ 2,154				$ (2,154)		$ (2,154)
14	Distribution	$ 5,489				$ (5,489)		$ (5,489)
15	Customer Accounts	$ -				$ -		$ -
16	Customer Service	$ -				$ -		$ -
17	Administration and General	$ 127				$ (127)	$ 13	$ (114)
18	Total O&M - Non-Labor	$ 7,802	$ -	$ -	$ -	$ (7,802)	$ 13	$ (7,789)

Notes and Source

Col.A: HECO-1708
Col.B&C: Unclear from responses reviewed
Col.D: Removes the General Inflation expense proposed by HECO
Col.E: Col.D - Col.A
Col.F: A&G Transfer

	Estimated A&G Transfer Ratio:	Dollars (H)	Transfer Ratio (I)	A&G Adjust. ($000) (J)	A&G Transfer (K)
19	A&G Operations	$ 73,880,465			
20	A&G Maintenance	$ 370,287			
21	Total O&M - Labor	$ 75,034,879			
22	Total O&M - Labor/Non-Labor On-Costs	$ 30,904,413			
23	Sum of A&G/Labor/Labor On-Costs	$ 180,190,043			
24	Total O&M - A&G/Emp Ben Transferred to Constr/Other	$ (18,475,425)	-0.10253	$ (127)	13

Col.H: HECO-1708
Col.I: Line 24 / Line 23
Col.J: Col.E, Line 17
Col.K: Col.I x Col.J

State of California | Public Utilities Commission
San Francisco

MEMORANDUM

Date : March 31, 2009

To : Division of Ratepayer Advocates and Water Division

From : M. G. Lyons, Program Supervisor
DRA Energy Cost of Service Branch

File No.: S-2559

Subject: Division of Ratepayer Advocates: Estimates of Non-labor and Wage Escalation Rates for 2009 through 2013 from the March 2009 IHS Global Insight U.S. Economic Outlook

The purpose of the monthly Escalation Memorandum is to inform division management of the trends in the general price level of utility non-labor expenses and wage contracts. Data are provided for 13 years, which include eight historic years, the estimated current year, and four forecasted years.

The following table summarizes the major changes in forecasted labor and non-labor inflation for years 2009 through 2013. Data for 2008 are provided as benchmarks. The factors for February 2009 are presented for comparison. Near-term, lagged CPI (Labor) is expected to run over 3.8% in 2009 due to sharp petroleum price increases in 2008. Non-labor inflation for 2009-13 is effectively checked by the 2008-09 recession and continued structural changes in the economy such as globalization and improved operating efficiencies. The rise of non-labor rates for 2008 is the result of temporary price increases in chemicals, metals, and the spike in 2008 refined oil prices. Labor escalation is constrained from 2010-2012 by changes in the labor market due to the 2008-09 recession, corporate structural change, outsourcing, and a rise in operating productivity.

FORECASTED INFLATION

	Labor		Non-labor	
	02/09	03/09	02/09	03/09
2008	2.9%	2.9%	6.3%	6.3%
2009	3.8%	3.8%	(0.8)%	(0.7)%
2010	(1.9)%	(1.9)%	0.0%	(0.1)%
2011	1.7%	1.5%	2.1%	2.5%
2012	2.2%	2.4%	2.5%	2.8%
2013	2.3%	2.3%	2.9%	2.8%
Compounded	11.7%	11.7%	13.7%	14.3%

Hawaiian Electric Company, Inc.
Ward Base Yard Capitalization
(Thousands of Dollars)
Test Year Ending December 31, 2009

Exhibit DOD-114
Docket No. 2008-0083

Line No.	Description	Amount	Reference
1	Ward Base Yard Capitalization	$ (145)	CA-IR-348(a) Account 932

Hawaiian Electric Company, Inc.
Vehicle Fuel Cost

Test Year Ending December 31, 2009

Line No.	Description				Amounts in Dollars	DOD Adjustment ($000)
	I. Calculation of Adjustment					
1	HECO 2009 Test Year Vehicle Fuel estimate (included in Vehicle Clearing)				$1,413,888	
	Fuel Type	2009 Estimated Usage	Current Prices as of 3/23/09	Adjusted Cost		
2	Biodiesel:	62,960	$2.42	152,363		
3	Unleaded:	296,823	$2.04	605,519		
4	Propane:	16,527	$2.37	39,169		
5	Misc: oil, lube, grease			182,508		
6	2009 Vehicle Fuel estimate at estimated average prices			$979,559	$979,559	
7	Difference				($434,329)	
8	% of vehicle clearings to O&M expense				61.62%	
9	Impact to O&M Expense				($267,633)	
	II. Impact to O&M Expense by Block of Accounts:					
10	Production Operation				$ (14,045)	$ (14)
11	Production Maintenance				$ (25,849)	$ (26)
12	Transmission Operation				$ (30,527)	$ (31)
13	Transmission Maintenance				$ (31,416)	$ (31)
14	Distribution Operation				$ (59,612)	$ (60)
15	Distribution Maintenance				$ (58,063)	$ (58)
16	Customer Accounts				$ (22,116)	$ (22)
17	Customer Services				$ (2,600)	$ (3)
18	A & G Operation				$ (20,431)	$ (20)
19	A & G Maintenance				$ (2,975)	$ (3)
20	Total				$ (267,633)	$ (268)
	III. Summarized Impact on Expenses					
21	Production					$ (40)
22	Transmission					$ (62)
23	Distribution					$ (118)
24	Customer Accounts					$ (22)
25	Customer Service					$ (3)
26	Administration and General					$ (23)
27	Total					$ (268)

Notes and Source

CA-IR-387

Hawaiian Electric Company, Inc.
Expiring Amortization
(Thousands of Dollars)
Test Year Ending December 31, 2009

Line No.	Description	Amount	Reference
	Expiring Amortization for Assets Retired on 9/4/2004:		
1	2009 Amortization Amount	$ 2,198	CA-IR-418
2	Reschedule expiring amortizaton over two years - Annual amortization amount	$ 1,099	Line 1 / 2 years
3	HECO's updated test year estimate	$ 1,924	HECO T-14 Update, pp 20 & 22
4	Adjustment for rescheduling expiring amortization	$ (825)	Line 2 - Line 3

Hawaiian Electric Company, Inc.
"Community Service Activities" Expenses
(Thousands of Dollars)
Test Year Ending December 31, 2009

Line No.	Description	Amount	Reference
1	Test Year 2009 Expenses for "Community Service Activities"	$ 361	Note A
2	Allocation between ratepayers and shareholders	50%	Testimony
3	Remove portion of "Community Service Activities" expense allocated to shareholders	$ (181)	

Notes

[A] CA-IR-151

Hawaiian Electric Company, Inc.
Interest Synchronization Adjustment
(Thousands of Dollars)
Test Year Ending December 31, 2009

DOD-118
Docket No. 2008-0083

Line No.	Description	Amount	Reference
	Adjustment on HECO's Update Filing		
1	Adjusted Rate Base	$ 1,308,855	DOD-103
2	Weighted Cost of Debt	2.38%	DOD-105
3	Synchronized Interest Expense	$ 31,151	Line 1 x Line 2
4	HECO "As Filed" Interest Expense	$ 31,793	(a)
5	Net Adjustment to Interest Expense	$ (642)	
6	Combined State/Federal Tax Rate	38.91%	DOD-102
7	Interest Synchronization Adjustment, Income Tax Expense Change	$ 250	

Notes

(a) HECO T-23 Update, Excel file
Pbase-Upd-lower sales-curr eff rates, "Support" tab, cells F104 - F112

Hawaiian Electric Company, Inc.
Depreciation and Amortization on 12/31/2008 Actual Plant
(Thousands of Dollars)
Test Year Ending December 31, 2009

DOD-119
Docket No. 2008-0083
Page 1 of 1

Line No.	Description	HECO Update Filing Amount (A)	On Actual 12/31/2008 Plant Amount (B)	Adjustment (C)
1	Depreciation & Amortization Expense	$ 92,979	$ 90,645	$ (2,334)
2	Less: Depreciation on Vehicles	$ (2,155)	$ (2,067)	$ 88
3	Depreciation and Amortization Expense	$ 90,824	$ 88,578	$ (2,246)
4	CIAC Amortization	$ (9,383)	$ (9,335)	$ 48
5	Net Adjustment	$ 81,441	$ 79,243	$ (2,198)

Notes and Source

		HECO Update		DOD 12/31/2008 Actual		
	Plant Group	Depreciable Plant (D)	Depreciation & Amortization (E)	Depreciable Plant (F)	Depreciation & Amortization (G)	Adjustment (H)
6	Production	$ 589,962	$ 9,954	$ 586,452	$ 9,929	$ (25)
7	Transmission	$ 596,329	$ 17,364	$ 594,665	$ 17,366	$ 2
8	Distribution	$ 1,185,587	$ 50,965	$ 1,177,950	$ 50,782	$ (183)
9	General	$ 174,647	$ 12,541	$ 178,990	$ 10,501	$ (2,040)
10	Vehicles	$ 29,638	$ 2,155	$ 28,431	$ 2,067	$ (88)
11	TOTAL	$ 2,576,163	$ 92,979	$ 2,566,488	$ 90,645	$ (2,334)
12	Less Vehicles					$ 88
13	Adjustment to Depreciation and Amortization Expense					$ (2,246)

Notes and Source

Col.A: HECO Rate Case Update, T-14, page 15 of 28, HECO-1408, Test Year Estimate 2009, lines 1 & 2
Col.B, F&G: HECO T-14 Update, page 17 of 28, HECO-1410
Col.C: Col.B - Col.A
Col.D&E: HECO T-14, page 17 of 28, HECO-1410
Col.H: Col.G - Col.E
Line 4:
Col.A: HECO Rate Case Update, T-14, page 23 of 28, HECO-1408, Test Year Estimate 2009, line 3
Col.B: Calculation from CA-IR-419

Hawaiian Electric Company, Inc.
Work Force Vacancies
(Thousands of Dollars)
Test Year Ending December 31, 2009

DOD-120
Docket No. 2008-0083

SUMMARY OF ADJUSTMENT ATTRIBUTED TO A REDUCTION IN HEADCOUNT
(T&D, Customer Acct., Customer Svc and A&G)

Line No.	Block of Accounts, Less PSOM	Labor Expense (Note 1)	Labor Expense Reduction Using Factor (Note 2)	Payroll Tax Reduction (Note 3)	Employee Benefits Reduction (Note 4)	Total Expense Reduction	HECO Proposed Expense Reduction	DOD Net Adjustment
	A	B	C=B*-Vacancy Rate	D=C*8.29%	E=(B/Total)	F=C+D+E	(G)	(H)
1	Transmission	$ 5,068	$ (167)	$ (14)	$ (55)	$ (236)	$ (169)	$ (67)
2	Distribution	$ 12,717	$ (420)	$ (35)	$ (137)	$ (592)	$ (424)	$ (168)
3	Customer Accounts	$ 8,102	$ (267)	$ (22)	$ (87)	$ (376)	$ (270)	$ (106)
4	Customer Service	$ 3,470	$ (115)	$ (10)	$ (37)	$ (162)	$ (116)	$ (46)
5	Administrative & General	$ 22,517	$ (743)	$ (62)	$ (242)	$ (1,047)	$ (750)	$ (297)
6	Total	$ 51,874	$ (1,712)	$ (143)	$ (559)	$ (2,414)	$ (1,729)	$ (684)

Notes and Source

	Note 1: See HECO T-8 update, HECO-809; HECO T-9 update, HECO-901; HECO T-10 update, HECO-1005; HECO T-11 update, HECO-1101.			
7	Note 2: Percent difference vacancy rate (13-mo. avg.):	See below	-3.30%	[A]
8	Note 3: Per HECO T-15 Update Attachment 6		8.29%	
9	Note 4: Per HECO T-15 Update, Attachment 6, employee benefits cost per employee		$ 14.7	
10	HECO filing 2009 test year average work force (T&D, Customer Accouns, Customer Service and A&G)			1,138 [B]
11	Reduction in 2009 average # of employees in HECO's filing		-38	
12	Total employee benefits reduction		$ (559)	[C] = [A] x [B]

Line	Work Force Data Points	Date	Actual	Budgeted	Difference	Vacancy Rate
13	Considered by HECO:	9/30/2006	1032	1122	(90)	-8.02%
14		12/31/2006	1041	1123	(82)	-7.30%
15		3/31/2007	1033	1086	(53)	-4.88%
16		6/30/2007	1058	1087	(29)	-2.67%
17		9/30/2007	1053	1093	(40)	-3.66%
18		12/31/2007	1056	1093	(37)	-3.39%
19		3/31/2008	1063	1103	(40)	-3.63%
20		6/30/2008	1079	1105	(26)	-2.35%
21		7/31/2008	1078	1112	(34)	-3.06%
22		9/30/2008	1066	1112	(46)	-4.14%
23		10/31/2008	1077	1113	(36)	-3.23%
	Average Vacancy Rates					
24	Average of all data points					-4.21%
25	2007 average (12/31/06 through 12/31/07)					-4.38%
26	2008 quarterly average, 10/31/08 used in place of 12/31/08 which was not considered by HECO)					-3.35%
27	Average of all data points from 6/30/2007 through 10/31/08					-3.27%

Hawaiian Electric Company, Inc.
Pension and OPEB Expense
(Thousands of Dollars)
Test Year Ending December 31, 2009

Line No.	Description	HECO Original Filing Amount (A)	HECO Update Filing Amount (B)	DOD Adjusted (C)	Cost Adjustment (D)
1	Pension	$ 14,623	$ 14,623	$ 14,623	$ -
2	OPEB	$ 3,853	$ 3,853	$ 3,853	$ -
3	Total	$ 18,476	$ 18,476	$ 18,476	$ -
4	Portion charged to O&M				74%
5	Adjustment to O&M Expense				$ -

Notes and Source

Col.A: HECO T-13, Exhibits HECO-1302 through HECO-1304

Col.B: DOD-IR-104 including 3/27/09 supplemental response. See below for details
HECO reported a higher amount but did not update its filing.

Col.C: Either use HECO's original filing or amount from HECO's last rate case on which the Pension and OPEB Adjustors were based.

Col.D: Col.C - Col.B

Col.E-G: DOD-IR-104 Supplement Attachment 3 (PensOPEB Feb Update):

	Account Description	Revised TY Est. 2009 (E)	Update Adjustment Identified By HECO (F)	Updated 2009 TY Est. Identified By HECO (G)	Included In Rates Per NPPC & NPBC Trackers (H)
6	Qualified Pension Plan	$ 14,623	$ 16,865 [1]	$ 31,488	$ 17,711
7	Other Postretirement Benefits*	$ 3,853	$ 1,698 [2]	$ 5,551	$ 6,350
8	Total Pension and OPEB	$ 18,476	$ 18,563	$ 37,039	$ 24,061

* Net of electric discount

[1] Adjustment for Feb update to estimated NPPC from Watson Wyatt Worldwide:

$	31,488	DOD-IR-104, Attachment 1, page 1
$	(14,623)	HECO-1302
$	16,865	

[2] Two adjustments were made resulting in a gross adjustment amount of $1,698 as follows:

a. Adjustment for Feb update to NPBC from Watson Wyatt Worldwide:

$	6,941	DOD-IR-104, Attachment 1, page 2
$	(5,224)	HECO-1304
$	1,717	

b. Updated executive life program (postretirement) portion deleted to simplify and limit issues in this rate case:

$	(892)	DOD-IR-104, Attachment 1, page 3
$	873	HECO-1303, page 3, line 7
$	(19)	

c. Total adjustment:

$	1,717
$	(19)
$	1,698

Col.H: DOD-IR-101 and Interim D&O 23749 (Oct.22, 2007)

Line 4: Portion Charged to O&M: 74% DOD-IR-81 and CA-IR-432

Hawaiian Electric Company, Inc.
Normalize Non-EPRI R&D Expense
(Thousands of Dollars)
Test Year Ending December 31, 2009

Line No.	Description		Amount	Reference
	Normalize Non-EPRI R&D:			
1	HECO's estimated 2009 R&D excluding EPRI dues	$	2,323	Note A
2	Normalized amount based on 3-year average:	$	1,533	Note B
3	Adjustment to normalize Non-EPRI R&D Expense	$	(790)	Line 2 - Line 1

Notes

[A] CA-IR-482
Non-EPRI R&D in O&M Expense

[B]	Year		Total R&D		EPRI Dues		Non-EPRI R&D
4	2004	$	2,823	$	1,529	$	1,294
5	2005	$	3,140	$	1,529	$	1,611
6	2006	$	1,291	$	-	$	1,291
7	2007	$	3,268	$	1,608	$	1,660
8	2008	$	3,255	$	1,608	$	1,647
9	TY 2009 Update	$	3,980	$	1,657	$	2,323
				Averages:			
10				2004 - 2008		$	1,501
11				2005 - 2008		$	1,552
12				**2006 - 2008**		**$**	**1,533**

Hawaiian Electric Company, Inc.
R&D Tax Credit on EPRI Dues
(Thousands of Dollars)
Test Year Ending December 31, 2009

Line No.	Description		Amount	Reference
	Normalize Non-EPRI R&D:			
1	R&D Tax Credit Reflected in HECO's Update	$	-	Note A
2	Net amount of 2009 R&D credit	$	(215)	Note B
3	Adjustment for R&D credit	$	(215)	Line 2 - Line 1

Notes

[A] CA-IR-360, CA-IR-363 and CA-IR-423
CA-IR-423(a) states that "this credit is not included in HECO's stand alone tax return included in the response to CA-IR-363."

[B]	Year		EPRI Dues		Net Amount Of 2009 R&D Tax Credit		Adjustment to Income Tax Expense	
	TY 2009 Update	$	1,657	$	215	$	(215)	CA-IR-423

Hawaiian Electric Company, Inc.
FUTA Tax Expense
(Thousands of Dollars)
Test Year Ending December 31, 2009

Line No.	Description	Amount	Reference
1	Reduce Payroll Tax Expense	$ (16)	[A]
2	Adjustment	$ (16)	

Notes and Source

[A] DOD-IR-92 (FUTA Surtax Extension) and CA-IR-361

Hawaiian Electric Company, Inc.
International Financial Reporting Standards
(Thousands of Dollars)
Test Year Ending December 31, 2009

DOD-125
Docket No. 2008-0083

Line No.	Description	Amount	Reference
	Defer 2/3 of HECO's 2009 budget for studying International Financial Reporting Standards		
1	HECO requested amount	$ 100	HECO T-11 update
2	Recommended allowance	$ 33	Testimony
3	Adjustment	$ (67)	

Notes and Source

CA-IR-342, DOD-IR-132 and CA-IR-479

Hawaiian Electric Company, Inc.
Rent Expense
(Thousands of Dollars)
Test Year Ending December 31, 2009

Line No.	Description	Amount		Reference
1	HECO requested amount	$	3,903	HECO T-14 update
2	Updated amount reflecting most current revisions	$	3,765	CA-IR-344 revised 3/30/09
3	Adjustment	$	(138)	

Notes and Source

CA-IR-344, DOD-IR-124

Hawaiian Electric Company, Inc.
Emission Fees
(Thousands of Dollars)
Test Year Ending December 31, 2009

Line No.	Description	Amount	Reference
1	HECO requested amount	$ 958	[A]
2	Updated amount reflecting most current revisions	$ 913	[B]
3	Adjustment	$ (45)	

Notes and Source

[A] HECO T-7 Update, Attachment 15; also see line 12, below

[B] CA-IR-213 and CA-IR-298; also see line 13 below

	Year or Period	HECO Estimated	Actual Amount Paid	Variance
4	2004	$ 741	$ 842	$ 101
5	2005	$ 954	$ 847	$ (107)
6	2006	$ 989	$ 846	$ (143)
7	2007	$ 898	$ 900	$ 2
8	2008	$ 874	$ 853	$ (21)
	Averages:			
9	2004-2008	$ 891	$ 858	$ (34)
10	2005-2008	$ 929	$ 862	$ (67)
11	2006-2008	$ 920	$ 866	$ (54)
12	2009 HECO original	$ 958		
13	2009 HECO revised	$ 913		

CERTIFICATE OF SERVICE

I hereby certify that one copy of the foregoing document was duly served upon the following parties, by personal service, hand-delivery, and/or U.S. mail, postage prepaid, and properly addressed pursuant to HAR sec. 6-61-21(d).

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